ANDERSON
EXPLORATION LTD.

1997 Annual Report

ABOUT THE COMPANY

Anderson Exploration Ltd. is a Calgary based senior oil and gas producer. The Company evolved from a program of oil and gas exploration, acquisition and development commenced by Mr. J.C. Anderson in 1968. Anderson Exploration became a public company in 1988. The common shares of Anderson Exploration are widely held and trade on The Toronto Stock Exchange under the symbol AXL. Anderson Exploration has a large oil and gas reserve base and operates approximately 80 percent of its production. The Company operates exclusively in western Canada after recently disposing of its operation in Argentina. The Company is leveraged to the North American natural gas market with over 65 percent of its reserves and revenues made up of gas and natural gas liquids. Anderson Exploration operates and is a 50 percent owner of Federated Pipe Lines Ltd. which transports crude oil and NGL through extensive pipeline systems in Alberta and British Columbia. The Company has an experienced group of dedicated people pursuing an excellent inventory of exploration, development and acquisition projects.

Annual General Meeting

The Annual General Meeting of Shareholders will be held on Wednesday, February 11, 1998 at 3:00 p.m. at the Westin Hotel, Calgary, Alberta.

Abbreviations Used in Annual Report

Bcf	—	billion cubic feet
Bpd	—	barrels per day
Mbbls	—	thousand barrels
Mcfd	—	thousand cubic feet per day
Mmbbls	—	million barrels
Mmbtu	—	million British thermal units
Mmcfd	—	million cubic feet per day
NGL	—	natural gas liquids

HIGHLIGHTS

	1997	1996	% Change
Financial			
(in thousands, except per share amounts)			
Total revenue	$ 750,047	$ 600,633	25
Revenue, net of royalties	$ 631,640	$ 509,460	24
Cash flow from operations	$ 383,045	$ 306,760	25
Per common share	$ 3.14	$ 2.54	24
Earnings	$ 87,943	$ 48,203	82
Per common share	$ 0.72	$ 0.40	80
Average shares outstanding	121,873	120,773	1
Net capital expenditures	$ 468,744	$ 247,376	89
Long term debt	$ 544,982	$ 512,767	6
Shareholders' equity	$ 986,071	$ 881,322	12
Operating			
Daily sales			
Natural gas (million cubic feet)	549	506	8
Liquids (barrels)			
Crude oil	27,472	24,097	14
NGL	5,669	5,489	3
Total liquids	33,141	29,586	12
Reserves			
Natural gas (billion cubic feet)			
Proven	1,768	1,798	(2)
Proven plus probable	2,713	2,694	1
Crude oil and NGL (thousand barrels)			
Proven	130,907	107,683	22
Proven plus probable	200,323	165,730	21
Undeveloped land (thousands of acres)			
Gross (western provinces)	4,396	4,308	2
Net (western provinces)	3,421	3,182	8
Average working interest (%)	78	74	5
Drilling activity (gross number of wells drilled in Canada)			
Oils wells	356	113	215
Gas wells	195	146	34
Dry holes	118	76	55
	669	335	100
Service wells	36	6	500
Total wells	705	341	107
Employees			
Calgary	347	293	18
Field	332	329	1

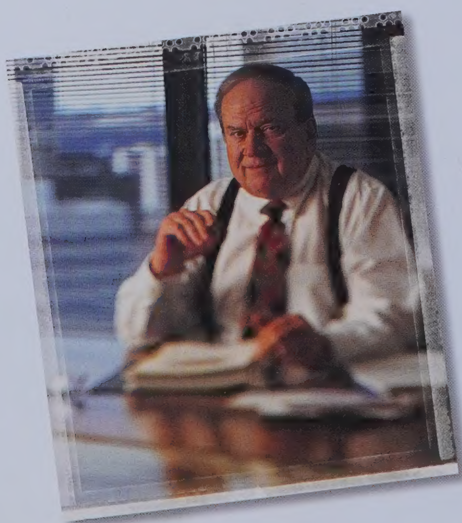
Our fiscal 1997 was a very active and successful year. We drilled a record number of wells and our net capital expenditures nearly doubled from the previous year. However, we kept our balance sheet in good shape as our debt to cash flow and debt to equity ratios declined. On a barrel equivalent basis, we increased our oil and gas sales by 10 percent and our proven reserves by seven percent. In an environment of increasing costs of doing business, we more than replaced our production at a reasonable cost of finding and development. Our commodity prices improved by 13 percent and this, coupled with our improved operating results, increased cash flow and earnings per share by 24 and 80 percent respectively. On balance, a very good year. We expect improvements in our operating performance in 1998 and, given reasonable commodity prices, in our financial performance as well.

CHAIRMAN'S MESSAGE

1997 in Review

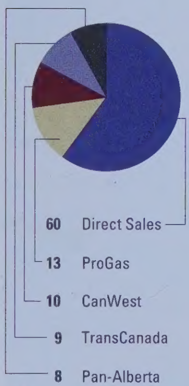
Natural gas sales in 1997 increased eight percent from 1996 to 549 million cubic feet per day, in line with our initial forecast of 550 million cubic feet per day. Oil and NGL sales increased 12 percent from 1996 to 33,141 barrels per day, about five percent less than our initial forecast for the year of 35,000 barrels per day. This shortfall versus forecast was due in part to an extended breakup period restricting our ability to truck oil to pipeline terminals and to the sale of our Argentina operations earlier than predicted.

Natural gas prices were up 20 percent and liquids prices were up five percent. Cash flow from operations increased 25 percent to $383 million or $3.14 per share and net earnings increased 82 percent to $88 million or $0.72 per share. Our Canadian oil and gas cash flow and earnings per barrel of oil equivalent improved 15 and 69 percent to $11.68 and $2.36 per barrel respectively. Net capital expenditures in 1997 were $469 million versus $247 million in 1996. Out of total capital expenditures, we spent the equivalent of 106 percent of our cash flow from operations on oil and gas related activities and replaced 163 percent of our production with proven reserves after revisions for a unit finding and development cost of $7.75 per barrel equivalent and $6.71 per barrel equivalent on a proven plus one half probable basis. Anderson Exploration's long term debt to cash flow ratio improved to 1.4 from 1.7. We enter 1998 with the resources to continue conducting a growth oriented capital program.



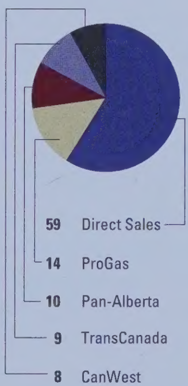
J.C. Anderson
Chairman & Chief Executive Officer

1997 Gas Sales Distribution
(% of Volume)



Total Gas Sales = 200.4 Bcf

1997 Gas Revenue Distribution
(% of $)



Total Gas Revenues = $381.9 Million

Natural Gas Market View

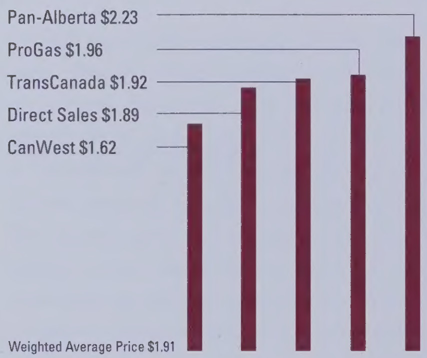
Anderson Exploration is perhaps the most gas leveraged of the senior Canadian producers. On a barrel equivalent basis, natural gas and NGL accounted for 69 percent of our 1997 sales volumes and 68 percent of our remaining proven reserves. In 1997, 63 percent of our Canadian oil and gas revenue came from gas and NGL. In the future we expect these numbers to stay in this range or increase. In 1998, excluding the Swan Hills acquisition amount and estimated pipeline expenditures, about 57 percent of our capital budget will be spent on gas projects and 36 percent on oil projects.

In the recent past, western Canadian industry gas delivery capacity has been in oversupply relative to take away pipeline capacity. This has kept downward pressure on Canadian prices relative to wellhead prices in the United States. We think that the excess industry deliverability is now about gone. In November, 1998 approximately one billion cubic feet per day of pipeline take away capacity will come on stream. This will extinguish any excess industry deliverability available at that time and will put significant upward pressure on prices. If the Alliance pipeline project to Chicago is completed two or three years later, and we think it or an equivalent project will be, our view is that the producing industry in western Canada will have difficulty filling export pipelines for a number of years. This will result in a further increase in natural gas prices.

Canadian exports to the U.S. have nearly tripled in the past 10 years and the easy ways of ramping up deliverability in Canada are now behind us as an industry. Future increases will be more difficult to achieve since the industry is now producing at maximum capacity and is fighting serious decline in existing production. The demand, however, is certainly there at the other end of the pipe. U.S. consumption is expected to be about 22.5 trillion cubic feet in 1998, more than a two percent increase year over year. This is a level not seen for 25 years when gas sold for pennies at the wellhead and the cost of energy was not a factor seriously considered in domestic, commercial and industrial applications. The increase in domestic U.S. production in 1998 is expected to be less than one percent at slightly over 19.2 trillion cubic feet. Most of the difference of about nine billion cubic feet per day will have to come from Canada. In calendar 1997, Canadian exports to the U.S. will average a bit over eight billion cubic feet per day.

All of this, we believe, bodes well for the future of Canadian wellhead gas prices. Although Anderson Exploration has experienced increases in its average gas price for the past two years, the deliverability-take away capacity relationship has made price predictions tenuous at best and prices have been erratic. Our average monthly prices varied from $1.45 to $3.06 in fiscal 1997. We believe we are now on the cusp of enjoying increased gas prices for a number of years.

1997 Gas Price
($/Mcf)



People

During the year, Henry Assen was promoted to Vice President, Marketing. With continuing intense activity in new facilities construction and upgrading of our producing infrastructure, Facilities was made a stand alone department with Drew Livingston as Manager. George Addison, who served Anderson Exploration for 24 years in the Peace River Country, most recently as District Superintendent at Fairview, Alberta, retired to pursue farming interests and we wish him well. Ron Strandquist was transferred to Fairview from Fort St. John, B.C. as District Superintendent and Tip Johnson was promoted to District Superintendent at Fort St. John. Anderson Exploration's field producing operations are divided into five districts and the District Superintendents and Jan Olthof, our Manager, Production here in Calgary, are highlighted in the Property Review section of this report. About one half of the people employed by Anderson Exploration work in our field producing operations and report to these gentlemen. The importance of the job our field staff do for the Company cannot be over emphasized.

Outlook

In 1998, we will increase our oil and gas sales volumes. Our current forecast is for average volumes of 38,500 barrels of oil and NGL and 590 million cubic feet of gas per day. We are operating on a capital budget totaling $505 million, which includes $98 million for the additional interest we purchased in early October in the company operated Swan Hills Unit No. 1. This acquisition replaces over 40 percent of our estimated 1998 sales with proven reserves and about 50 percent on the basis of proven plus one half probable reserves so we are well on our way in that regard.

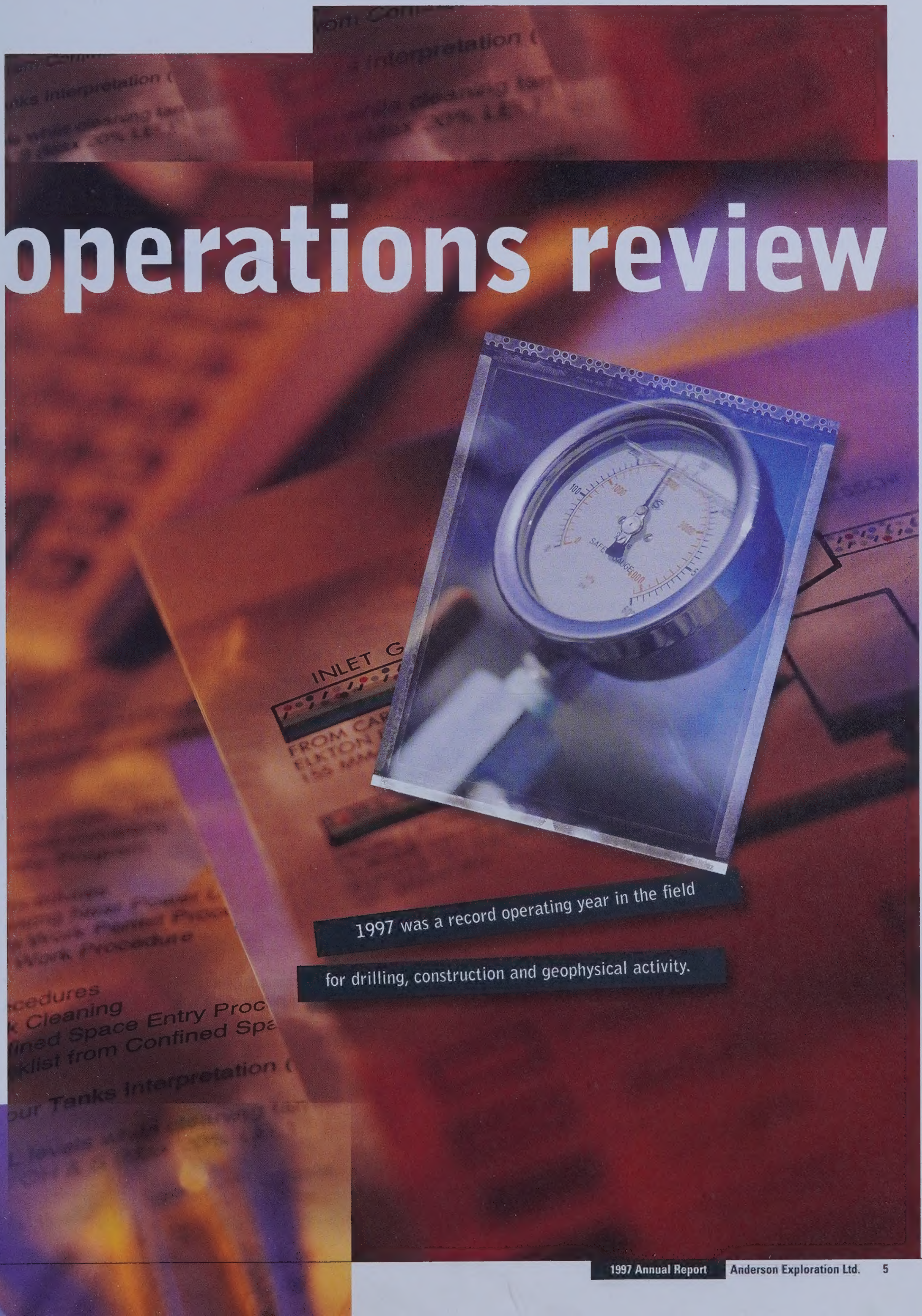
Our level of cash flow and earnings will be very sensitive to commodity prices, of course. At this juncture, we expect our average Canadian oil and NGL price to be less than the $25.36 per barrel experienced in 1997. We expect gas prices for 1998 to approximate our 1997 experience, with a price bump coming late in calendar 1998. Our first half financial results in 1997 were very strong due to excellent oil prices and very buoyant gas prices in the middle of the six month period. We probably won't have comparable liquids prices this year in our first half or gas prices which reach the peak they did last year. For example, the WTI crude price averaged $US 24.52 per barrel in the first quarter of fiscal 1997 while it averaged only $US 20.75 per barrel in October and November this year. The bottom line is that our financial results for the first half of this year will probably not meet last year's results. However, we should have a good year. We expect that industry will maintain a very high level of activity in fiscal 1998. High levels of land sale activity are anticipated. We intend to maintain our historic low levels of administrative and operating costs, however, the increase in the cost of doing business that we are experiencing is a matter for concern.

I take this opportunity to thank our people for their exemplary efforts in what proved to be a very busy year. I am confident that they will continue this performance for the benefit of you, the shareholders. Be assured that we all value your support.

J.C. Anderson

J.C. Anderson
Chairman & Chief Executive Officer
December 29, 1997

operations review



1997 was a record operating year in the field

for drilling, construction and geophysical activity.

OPERATIONS REVIEW

Land

In 1997, Anderson Exploration's undeveloped land inventory in the western provinces increased eight percent to 3,421,000 net acres. This undeveloped land base is located 66 percent in Alberta, 17 percent in British Columbia, 16 percent in Saskatchewan and one percent in Manitoba. The average working interest in this land base increased to 78 percent in 1997 compared to 74 percent in 1996.

Industry activity at Crown sales was intense and very competitive during 1997. In the four western provinces for the year ended September 30, 1997, approximately $1.3 billion was paid by industry for 16.3 million acres of petroleum and natural gas rights, excluding oil sands rights, compared to $864 million for 14.2 million acres in the prior year. To support its active exploration and development drilling program, the Company took an aggressive approach at provincial land sales during 1997, increasing its total expenditures 64 percent over 1996 while acquiring essentially the same amount of acreage. The Company directed most of its acquisition expenditures to Alberta and British Columbia, with 67 and 28 percent of expenditures respectively. Anderson Exploration expects to be active at Crown sales again in 1998 in order to support growth oriented exploration and development programs.

Summary of Undeveloped Working Interest Land Holdings

at September 30	1997		1996	
Thousands of Acres	Gross	Net	Gross	Net
Western Provinces	4,396	3,421	4,308	3,182
Other	1,323	210	1,710	321
Total	5,719	3,631	6,018	3,503

Crown Sale Land Acquisitions

	1997	1996
Expenditures ($000s)	$ 37,995	$ 23,206
Net Acres Acquired	407,951	404,633
Price Per Acre	$ 93	$ 57

Drilling Activity

During 1997, Anderson Exploration participated in drilling 669 wells for oil and gas versus 335 in 1996. This represents a record annual number of wells for the Company. The average working interest in the wells was 64 percent versus 63 percent in 1996. In addition, 36 service wells were drilled

including 25 water injection wells in one waterflood project. Expenditures for the drilling, completion and recompletion of wells in Canada in 1997 were $183 million versus $101 million in 1996. The Company expects that 1998 will also be an active year for drilling, however, total wells drilled will probably not exceed 1997 totals as the Company will be pursuing deeper targets at higher working interests.

	1997		1996	
	Gross	Net	Gross	Net
Oil wells	356	232	113	54
Gas wells	195	110	146	96
Dry holes	118	84	76	60
	669	426	335	210
Service wells	36	12	6	4
Total wells	705	438	341	214

Construction Activity

In 1997, Anderson Exploration spent $123 million constructing new and expanding existing production facilities versus $51 million in 1996. The two most active construction areas were northeast Alberta and northeast British Columbia. Several projects were constructed in northeast Alberta during a three month winter construction season. The Woodenhouse gas system, which was installed one year ago, was expanded with the addition of three wells and additional compression. At Corn Lake, Hospital Creek and Red Earth, 15 gas wells were tied into facilities operated by another Company through 43 miles of new pipeline. In the Kirby area, additional gas wells were connected to gathering systems and new compression was added to existing facilities. In northeast British Columbia, a gas compression and dehydration facility was installed and additional wells were tied in at Birley. At Zaremba, five wells were tied into a new compression and dehydration facility. The existing Nig Creek plant and gathering system were expanded to increase capacity to 40 million cubic feet per day.

During the year, work commenced on two significant facilities designed to process approximately 56 million cubic feet per day of slightly sour gas at Cecil and Normandville in the Peace River Arch area of northwest Alberta. The Company's share of capacity is about 50 percent with these facilities scheduled for completion in fiscal 1998.

In the Hayter oil field, surface facilities were expanded by adding three new production pads and extending two existing pads. Four hydrocyclone units were installed on the pads to supplement the experimental unit installed in 1995. These units are each capable of separating 25,000 barrels per day of water from the production stream for injection into large diameter disposal wells adjacent to the units. Residual fluid is pipelined to a central battery facility for final processing. At Innes in southeast Saskatchewan, new battery and gathering system facilities were installed to handle up to 6,000 barrels of fluid per day. At Gainsborough, also in southeast Saskatchewan, work began on the installation of an extensive gathering system and central tank battery which will facilitate increases in oil production in 1998.

Production/Sales

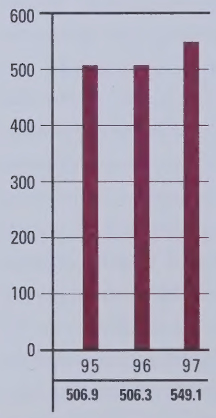
In 1997, Anderson Exploration's gas sales increased eight percent over 1996, averaging 549 million cubic feet per day. During the year, the Company estimates that it added about 120 million cubic feet per day of gas sales capacity by optimizing existing properties and placing new properties onstream. As the average annualized sales increase was 43 million cubic feet per day, the remainder of the sales capacity increase compensated for decline in existing producing properties. Leismer/Kirby in northeast Alberta remained the Company's largest gas producing property contributing 69.7 million cubic feet per day, approximately 13 percent of total sales. Sales from the second largest property, Dunvegan in northwest Alberta, increased about 36 percent over 1996 to 67.3 million cubic feet per day due to the full year impact of the deliverability expansion project completed last year and completion of the acid gas removal and injection system at the Dunvegan plant early this year. The Dunvegan plant, a Unit facility, now processes considerable gas production from recent discoveries outside the Dunvegan Unit boundary. The third most significant area, Birley/Wargen in northeast British Columbia, is essentially a new producing area which contributed 18.1 million cubic feet per day of sales in 1997 due to a successful 1996/1997 winter drilling and tie-in program and a property acquisition near the end of the second quarter. The nucleus of the Company's acreage position in this area came from the Home Oil side of the business combination two years ago. There was no production at the time of the combination but Anderson Exploration recognized the area's potential.

Crude oil sales averaged 27,472 barrels per day in 1997, up 14 percent from 1996. Swan Hills remained the Company's largest oil producing area providing about 14 percent of

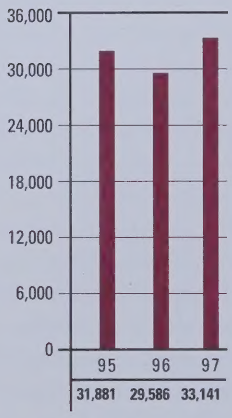
total Company oil sales. Initiatives undertaken as operator of the Swan Hills field led to the Company being successful in arresting the previously experienced high production decline rate. Between 1995 and 1996, production declined at a rate of 12 percent, but in 1997 the annualized production rate increased slightly. This result was achieved by implementing a successful horizontal well miscible injection project, conducting other drilling and initiating a workover program to shut off water production. During the year, the Lloydminster area became the Company's second largest oil producing area with an average of 2,328 barrels per day of heavy oil production added.

Although a number of the Company's existing oil and gas properties will experience declines in fiscal 1998, significant percentage increases in oil sales are expected, notably at Swan Hills, Lloydminster, Eagle, Innes, Pembina and Gainsborough and in gas sales at Birley/Wargen, Woodenhouse, Belloy/Cindy and Normandville.

Daily Natural Gas Production (Mmcfd)



Daily Oil & NGL Production (Bpd)



Daily Average Sales

	1997	1996
Natural Gas (Mcfd)		
Leismer/Kirby	69,720	78,355
Dunvegan	67,297	49,664
Birley/Wargen	18,131	662
Ring Border	15,931	16,748
Pica/Jack	15,705	20,604
Eaglesham/Culp	15,379	15,469
Woodenhouse	14,725	3,837
Belloy/Cindy	14,685	12,832
Peggo/Pesh	14,306	15,831
Blackstone	14,293	4,997
Hines Creek	13,996	14,578
Harmattan	12,904	12,182
Mistahae	12,789	9,473
Saddle Hills	11,384	10,016
Wapiti/Karr	11,032	13,967
Normandville	10,283	7,951
Kotaneelee	10,096	10,673
John Lake	9,723	4,396
Valhalla	9,525	16,485
Marten Hills	9,189	9,603
Moose Mountain	8,343	8,217
Other & Royalty	169,686	169,787
Total	549,122	506,327

Daily Average Sales

	1997	1996
Oil & NGL (Bpd)		
Swan Hills	3,768	3,724
Lloydminster Heavy	2,846	518
Hayter	2,435	1,797
Valhalla	1,882	1,971
Eagle	1,783	1,759
Mitsue	1,524	1,739
Innes	997	884
Stoddart	995	892
Pierson	965	1,159
Virginia Hills	957	959
Pembina	896	586
Cecil/Royce	529	352
Gainsborough	502	21
Genesee/Highvale	488	531
Harmattan	460	491
Wood River/Bashaw	451	584
Progress	403	215
Normandville	368	398
Turner Valley	357	321
Eaglesham/Culp	293	424
Provost	289	262
Argentina & Other	4,284	4,510
	27,472	24,097
NGL	5,669	5,489
Total	33,141	29,586

1997 Quarterly Sales

	Q1	Q2	Q3	Q4	Year
Oil (Bpd)	26,464	27,834	27,063	28,528	27,472
NGL (Bpd)	6,701	5,752	5,023	5,197	5,669
Liquids (Bpd)	33,165	33,586	32,086	33,725	33,141
Gas (Mmcfd)	542	543	563	548	549

Reserves

In 1997, Anderson Exploration replaced 163 percent of production with proven reserve additions, net of revisions, by spending 106 percent of cash flow from operations on capital expenditures attributable to oil and gas. Before revisions, the Company added 201 billion cubic feet of proven gas reserves and 31 million barrels of oil and NGL with the drill bit and net property acquisitions. At year end, after revisions, proven natural gas reserves were down approximately two percent and proven liquids reserves were up 22 percent from the previous year.

Before revisions, the Company's finding and development costs were $7.92 per barrel of oil equivalent for proven reserves and $6.49 per barrel of oil equivalent for proven plus one half probable reserves. The finding and development cost calculations are based on oil and gas related capital expenditures of $406 million net of disposition proceeds for the Argentina reserves. Finding and development costs on a unit basis were 17 percent higher than in 1996 due to substantial increases in the cost of doing business. While revisions to proven reserves on a barrel equivalent basis were positive, the Company revised probable reserves downward by four percent due primarily to poorer than expected performance in eastern Alberta shallow gas properties.

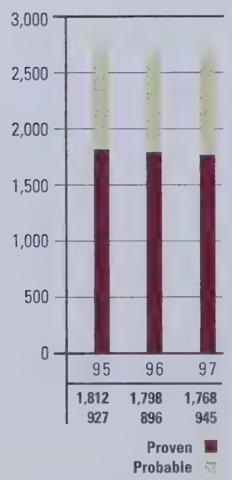
In 1997, the Company continued to be active in the property acquisition market. Anderson Exploration completed 40 property acquisition transactions at a total cost of $72.3 million. Proven reserves were acquired at an average cost of $6.54 per barrel of oil equivalent and $4.96 for proven plus one half probable reserves. On the disposition side, the Company sold 17 properties for total proceeds of $49.5 million. The sale of its Argentina subsidiary disposed of all of the Company's reserves in that country and represented 95 percent of total reserve dispositions. Dispositions resulted in an average realization of $7.64 per barrel of oil equivalent for proven reserves and $5.88 for proven plus one half probable reserves.

The Company's oil and NGL reserve life indices are 10.8 years on a proven reserve basis and 16.5 years on a proven plus probable basis. The gas reserve life indices are 8.8 years for proven and 13.5 years for proven plus probable reserves. In the last 16 months, approximately 52 percent of Anderson Exploration's reserves were estimated by an independent engineering consultant with the balance of the reserves estimated by Company engineering personnel. The Company's intention is to have a minimum of 25 percent of its reserves evaluated annually by independent consultants.

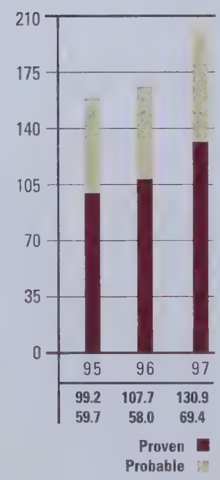
1997 Reserve Additions & Revisions

	Proven	Probable	Total
Natural Gas (Bcf)			
Drilling	153	59	212
Property Acquisitions	53	48	101
Property Dispositions	(5)	(2)	(7)
Total Additions	201	105	306
Revisions	(31)	(56)	(87)
Sales	(200)	–	(200)
Total	(30)	49	19
Crude Oil & NGL (Mbbls)			
Drilling	31,273	13,656	44,929
Property Acquisitions	5,805	2,223	8,028
Argentina Disposition	(5,974)	(3,721)	(9,695)
Property Dispositions	(20)	–	(20)
Total Additions	31,084	12,158	43,242
Revisions	4,237	(789)	3,448
Sales	(12,097)	–	(12,097)
Total	23,224	11,369	34,593

Natural Gas Reserves
(Bcf)



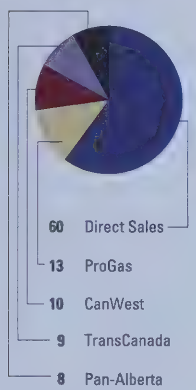
Oil & NGL Reserves
(Mmbbls)



Year End Reserves – Company Working Interest

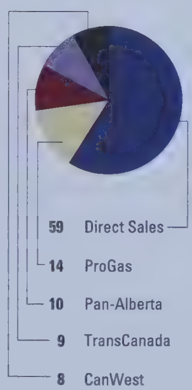
	Proven	Probable	Total
Natural Gas (Bcf)			
As at September 30, 1996	1,798	896	2,694
1997 Additions & Revisions	170	49	219
1997 Sales	(200)	–	(200)
As at September 30, 1997	1,768	945	2,713
Crude Oil & NGL (Mbbls)			
As at September 30, 1996	107,683	58,047	165,730
1997 Additions & Revisions	35,321	11,369	46,690
1997 Sales	(12,097)	–	(12,097)
As at September 30, 1997	130,907	69,416	200,323

1997 **Gas Sales Distribution**
(% of Volume)



Total Gas Sales = 200.4 Bcf

1997 **Gas Revenue Distribution**
(% of $)



Total Gas Revenues = $381.9 Million

Marketing and Product Prices

Cold weather across North America during the early months of the 1996-1997 heating season resulted in some relatively high average monthly prices during the first half of Anderson Exploration's 1997 fiscal year, but it was a roller coaster ride. Gas prices on the NYMEX peaked at $US 4.25 per Mmbtu in January, 1997 when the Company realized an average price of $3.06 per thousand cubic feet, exactly twice the price realized in October, 1996. Prices softened during the remainder of the year, however, the Company's average annual gas price increased for the second consecutive year. Worldwide demand for oil continued to increase substantially. Oil prices were very strong early in the year, then moderated, but on average the Company realized a slightly higher price than in 1996, the third consecutive annual increase.

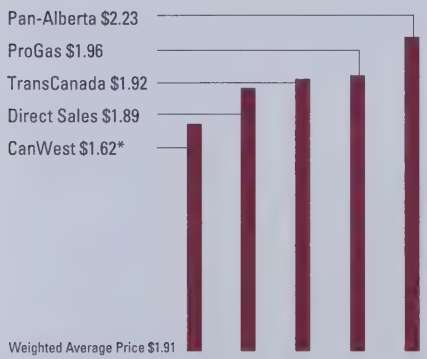
Natural Gas

Anderson Exploration's average natural gas price increased 20 percent over 1996 to $1.91 per thousand cubic feet at the plant gate. Monthly average prices were especially volatile in 1997, ranging from a high of $3.06 in January, 1997 to a low of $1.45 per thousand cubic feet in March. In 1997, the Company sold 40 percent of its natural gas to supply aggregators including TransCanada Gas Services, Pan-Alberta, ProGas and CanWest. Aggregators sell gas to a variety of United States and Canadian markets along pipeline routes, generally at indexed prices, and deduct a marketing fee for their services. Aggregator netbacks were especially strong during the winter price spike. The other 60 percent of Anderson Exploration's gas portfolio was sold directly by the Company to a wide variety of markets, including power generators, industrial end users, marketing intermediaries and local distribution companies. This component of the portfolio is comprised of contracts with fixed and indexed prices with terms ranging from day-to-day spot sales to commitments of up to 20 years. Direct sales provided attractive netbacks in 1997. For the 1998 fiscal year, the Company's gas sales portfolio remains similar except that aggregator sales will decrease slightly. Currently the Company has contracted approximately 159 million cubic feet per day of its 1998 direct sales volumes at an average fixed plant gate price of $2.00 per thousand cubic feet. Anderson Exploration's exposure to the Alberta spot market is expected to increase modestly in 1998.

Crude Oil and NGL

The West Texas Intermediate (WTI) price for light sweet crude at Cushing, Oklahoma quoted on the NYMEX is the benchmark for most crude oil prices in North America, including Edmonton, Alberta. The average price for WTI in fiscal 1997 increased seven percent to $US 21.76 per barrel. The price received for Anderson Exploration's Canadian crude oil production, adjusted for exchange rate, quality and transportation, is based on the daily posted price at Edmonton. Despite a slightly heavier crude mix in 1997, the Company's average price for Canadian sales was $25.37 per barrel, up marginally from 1996. In 1997, 64 percent of the Company's Canadian crude oil was sold directly to U.S. and Canadian refiners with the balance sold to marketing intermediaries.

1997 Gas Price
($/Mcf)



* Gas price includes both wellhead and plantgate sales.

Approximately 18 percent of Anderson Exploration's total liquids sales are NGL. The Company sells its NGL as a mix or as individual components such as propane, butane and condensate. NGL prices were strong in 1997, reflecting low propane and butane inventories and significantly increased demand for condensate as a diluent for transport of heavy oil. Anderson Exploration's propane and butane sales are indexed to posted prices at NGL market centres such as Edmonton, Alberta, Conway, Kansas and Mont Belvieu, Texas. In 1997, the Company's propane prices averaged $21.89 per barrel, an impressive year over year increase of 50 percent. Butane prices increased by 35 percent to $18.03 per barrel. Condensate commanded a premium to light sweet crude and increased demand has developed an active spot market for this product. The Company's 1997 condensate price rose by 21 percent averaging a strong $30.06 per barrel. The Company realized an average NGL price of $25.33 per barrel in 1997, an increase of 30 percent compared to 1996.

Historical Average Canadian Prices Before Hedging

Fiscal Year	Oil $ per barrel	Gas $ per mcf
1985	33.76	2.82
1986	23.49	2.46
1987	21.65	1.87
1988	18.75	1.68
1989	18.49	1.65
1990	22.16	1.70
1991	24.19	1.52
1992	20.29	1.33
1993	20.66	1.67
1994	19.52	1.98
1995	22.05	1.43
1996	25.22	1.59
1997	25.37	1.91

Straddle Plants

Anderson Exploration owns an average interest of 10.4 percent in two straddle plants located at Empress, Alberta. These plants are located on main transmission lines and process natural gas being exported from Alberta extracting NGL, primarily propane and butane, from the gas stream. Anderson Exploration processes its own gas at these plants plus a small amount of third party gas. The Company's share of the NGL produced from these facilities in 1997 was 1,827 barrels per day. These volumes are not included in the Company's reported sales volumes. The Company currently enjoys the significant difference between the value of the products which would be sold as additional heating value in the natural gas stream versus the value of the NGL extracted and sold as liquid. In 1997, high propane and butane prices provided an excellent return on Anderson Exploration's investment in these facilities.

Pipeline Operations

Anderson Exploration operates and is a 50 percent owner of Federated Pipe Lines Ltd. Federated's extensive pipeline system transports crude oil and NGL in Alberta and crude oil in British Columbia. Federated's 1,700 miles of pipelines have a capacity to move about 205,000 barrels of crude oil and 150,000 barrels of NGL per day. In 1997, throughput increased four percent over 1996 to 237,000 barrels per day.

The main crude oil system in Alberta transports oil from oil fields in the Swan Hills area northwest of Edmonton to Edmonton refineries and export pipelines. Federated's British Columbia pipeline transports crude oil, gathered by others and delivered to Federated near Taylor, to a refinery in Prince George and to a connection with another pipeline at Kamloops which transports oil to the west coast.

Federated Throughput (Bpd)

	1997	1996
Crude Oil	154,000	148,000
NGL	83,000	79,000
Total	237,000	227,000

The Federated NGL system moves NGL to industry facilities at Fort Saskatchewan located just east of Edmonton. NGL is transported to Fort Saskatchewan from the Caroline gas plant north of Calgary and from liquids rich gas fields south and west of Edmonton. As well, ethane rich NGLs are transported from Fort Saskatchewan northwest to the Swan Hills area for use in miscible floods in four major oil fields.

Pipeline operations provide the Company with a reliable and steady stream of cash flow and earnings. In 1997, the pipeline contribution to Anderson Exploration's cash flow was $10.3 million and to earnings was $7.7 million.

Federated has initiated construction on the largest expansion project in its history. The $110 million expansion will involve the construction of 280 miles of new mainline pipe with attendant pump stations, storage facilities and truck terminals. It will connect crude oil and NGL at Taylor, British Columbia, crude oil at Doe Creek, Alberta and crude oil and NGL at the Anderson Dunvegan gas plant located in the Peace River Arch area of Alberta. The expansion will feed these products into spare capacity in Federated's existing crude oil and NGL pipelines for onward transportation to markets in Edmonton and Fort Saskatchewan. This new pipeline will extend Federated's service into some of the most prospective regions in the western Canadian basin. It will provide producers in northeast British Columbia and northwest Alberta, including Anderson Exploration, with a competitive, alternate pipeline system. Federated has contracted approximately 75 percent of the capacity on the pipeline, indicating a high level of producer confidence in the Federated system. The new pipeline is expected to be operational in April, 1998.

Safety and Environment

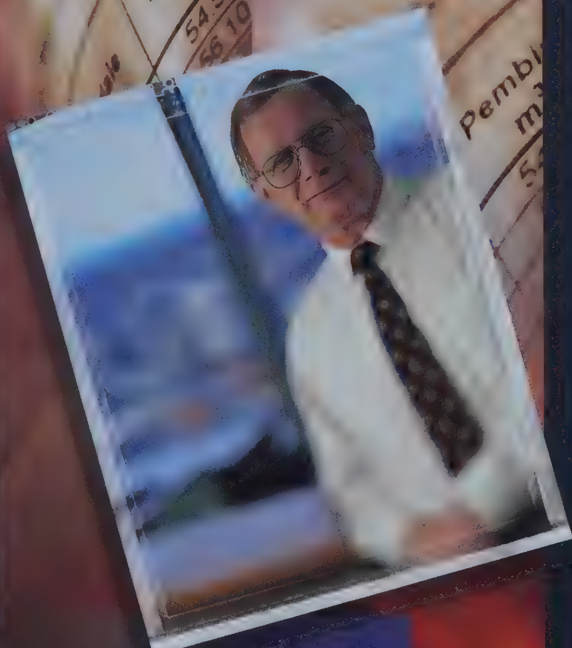
Anderson Exploration's operating practices include a strong emphasis on safety and environmental protection. Key safety and environmental programs are implemented to ensure compliance with applicable regulations. A program of internal compliance audits, environmental liability assessments and safety inspections is well established. An effective system for reporting safety and environmental incidents is in place and programs for remediating and reclaiming sites are established.

In 1997, Alberta Occupational Health and Safety completed a review of the Company's safety program. The review confirmed that the program contains all the key elements of a sound safety program. During the year, Anderson Exploration expanded safety training to include a revised employee orientation program. Driver training and collision avoidance workshops were completed at selected sites and helped to reduce vehicle accident rates in these areas. The development of a field operations Task Competency training program was also initiated. Production, pipeline and site specific drilling emergency response plans have been prepared and implemented for all Company operations. Emergency response training included crisis communication training for key field and Calgary office staff.

In 1997, the Company's efforts were focused on developing management programs to improve environmental protection performance. Comprehensive environmental audits of all production and pipeline facilities are being completed over a five year period. Action plans are prepared and implemented to address any concerns identified. In keeping with the Voluntary Challenge issued by the Federal Government, Anderson Exploration continues its concentrated efforts to minimize and reduce gas emissions. During the year, a Company-wide waste management program was implemented. The program includes site specific waste management plans for all operated facilities. The Company also established standards for the storage of products and wastes. Remediation of high priority sites continued in several areas during the year. The most significant activities were in older fields at Turner Valley, Carstairs and Swan Hills. During 1997, the Company received 60 Reclamation Certificates for successfully reclaimed well sites. Additional locations requiring reclamation have been identified, with work to be completed over the next several years.

property review

"Our producing operations stretch from the southeast tip of the Yukon Territory to southwest Manitoba. Our field production function is divided into five districts, each supervised by a District Superintendent on site who reports to me here in Calgary. We operate about 80 percent of our production and about half of all the people employed by Anderson Exploration are involved in our field producing operations. The mapped areas shown in this Property Review accounted for about 95 percent of our 1997 production. Once wells are drilled, plants built and major facilities installed, we take over. Our job is to maintain our production at the highest possible level at the lowest possible cost. Our operating costs on a barrel equivalent basis are among the lowest in the industry, although in 1997 we had some problems with high operating costs associated with start up of our newly established heavy oil operation. We conduct our operations with emphasis on protection of the environment and the safety of our employees and the communities in which we operate."

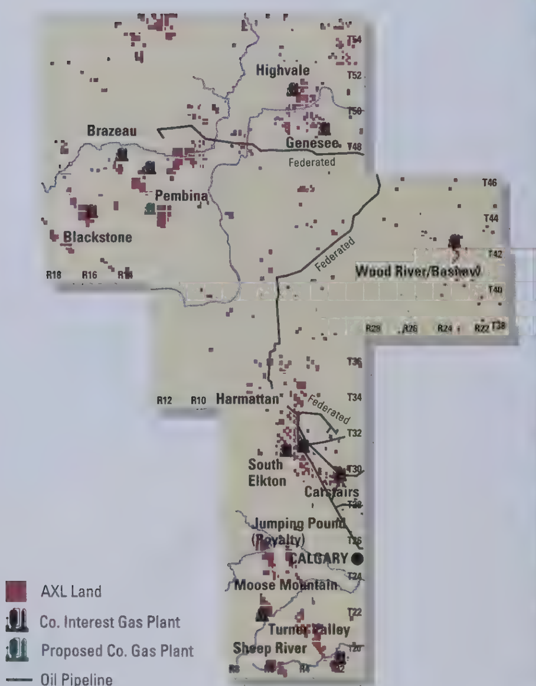


JAN OLTHOF
Manager, Production
Calgary, Alberta

"My district is the largest in area, stretching from the southern Alberta Foothills to southeast Manitoba. We operate production in the oldest field in the Company portfolio, Turner Valley, about 20 miles southwest of downtown Calgary. We also operate most of the Company's sour gas production just north of the city. In fiscal 1997, production in the district increased about 16 percent to over 14,000 barrels of oil equivalent per day. Most of our 1998 oil production increases will be from southeast Saskatchewan. Gas production will be enhanced by the tie-in of a 1997 Elkton zone rich gas discovery to the Harmattan Plant."

ROB CURSONS

District Superintendent
Carstairs, Alberta



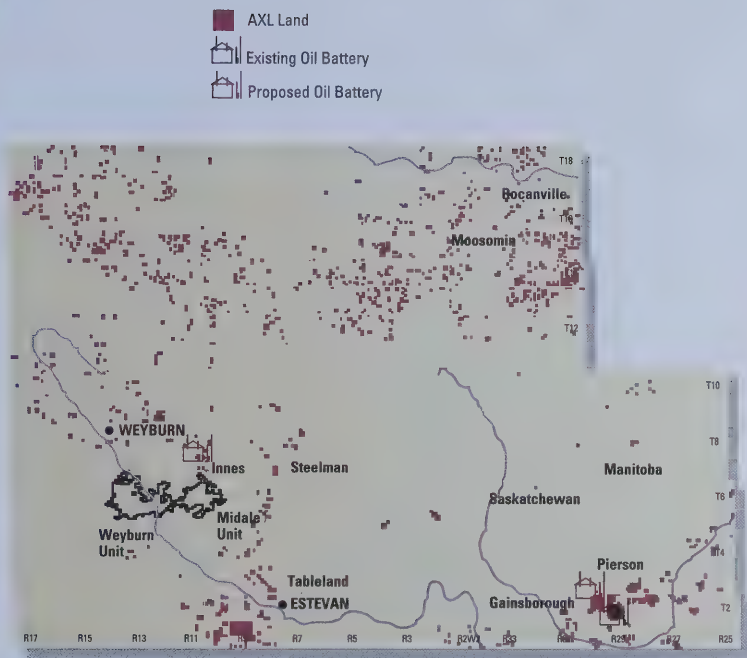
Region: **CENTRAL AND SW ALBERTA**

1997 Activity & Results

- Sales – 4,640 Bpd and 63 Mmcfd
- 11,733 net undeveloped acres acquired
- 145,830 net undeveloped acres at year end
- Drilled 25 gross (5 net) wells, resulting in 14 oil, 9 gas and 2 dry
- Tied in 2 Nisku sour wells

1998 Planned Activity

- Drill 11 gross (7 net) exploration wells and 21 gross (6 net) development wells
- Construct sweet gas plant at Pembina
- Tie-in new gas discovery at Carstairs
- Tie-in gas wells at Blackstone



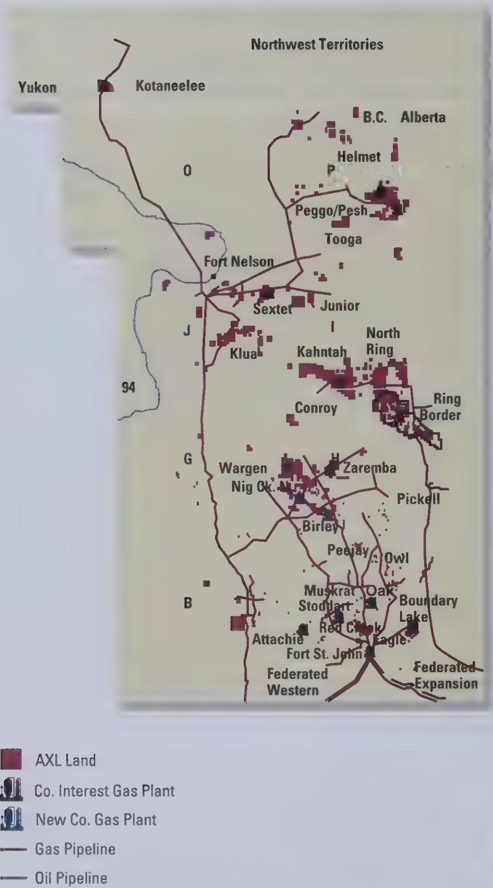
Region: SE SASKATCHEWAN AND MANITOBA

1997 Activity & Results

- Sales – 3,143 Bpd
- 36,785 net undeveloped acres acquired
- 250,332 net undeveloped acres at year end
- Drilled 96 gross (35 net) wells, resulting in 83 oil, 2 service and 11 dry
- Completed new production facilities at Innes

1998 Planned Activity

- Drill 16 gross (16 net) exploration wells and 47 gross (32 net) development wells
- Complete new battery and associated gathering lines at Gainsborough
- Start development drilling at Rocanville and Steelman
- Horizontal wells at Innes and Gainsborough



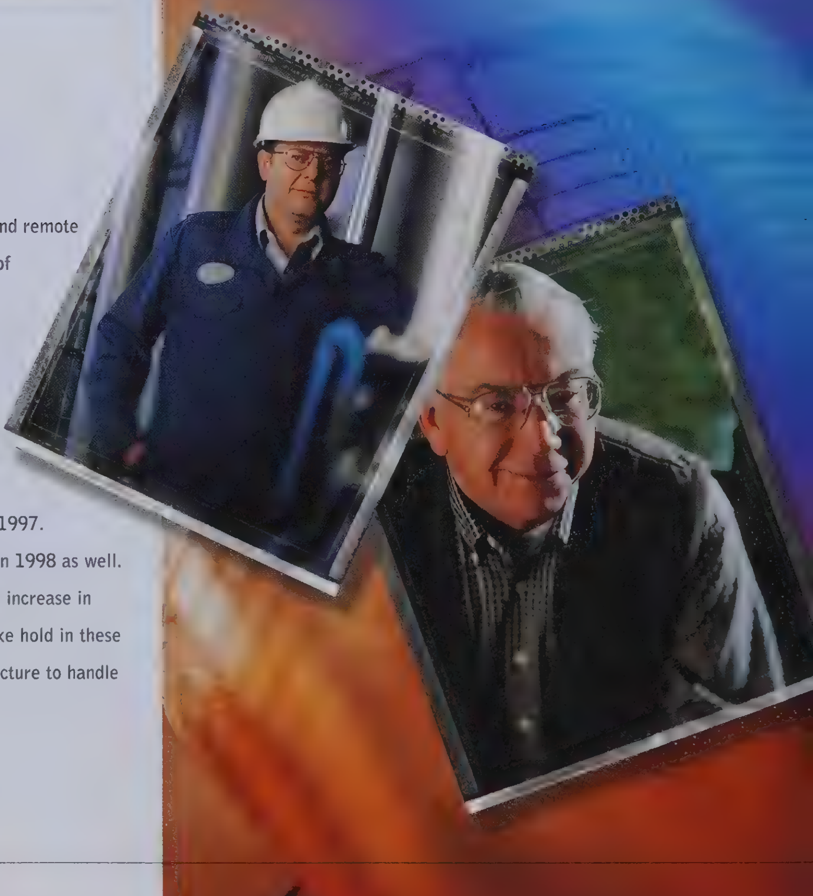
Region: **NE BRITISH COLUMBIA/YUKON**

1997 Activity & Results

- Sales – 4,098 Bpd and 82 Mmcfd
- 78,495 net undeveloped acres acquired
- 582,602 net undeveloped acres at year end
- Drilled 55 gross (27 net) wells, resulting in 9 oil, 37 gas and 9 dry
- Purchased additional interest in Wargen and Fort St. John areas

1998 Planned Activity

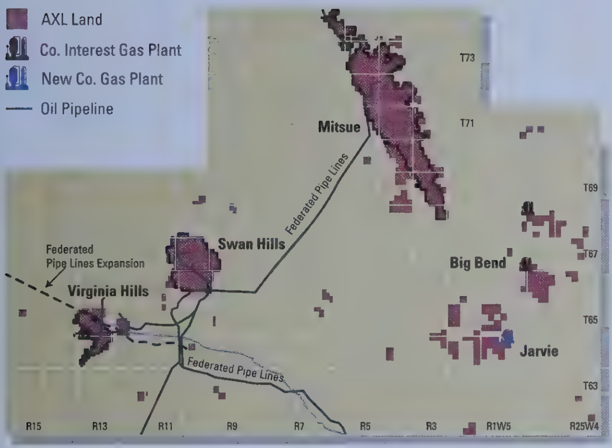
- Drill 40 gross (29 net) exploration wells and 48 gross (32 net) development wells
- Infill and exploration drilling at Kahntah
- Drilling and workover programs at Eagle and Stoddart
- Implement new waterflood projects at Owl and Oak
- 3D seismic and exploratory drilling at Red Creek



"My district contains perhaps the most varied and remote terrain. We operate on farmland in the vicinity of Fort St. John and in a very mountainous area at Kotaneelee in the Yukon Territory where our operating crews are flown in and out at two week intervals. In the past two years, a new gas producing area has been developed at Birley/Wargen, a winter only access area for drilling, where production increased 27 fold in 1997. I expect significant production increases there in 1998 as well. Our oil production at Eagle and Stoddart should increase in 1998 as our workover and drilling programs take hold in these fields. We have capacity in our surface infrastructure to handle the additional production."

TIP JOHNSON

District Superintendent
Fort St. John, British Columbia



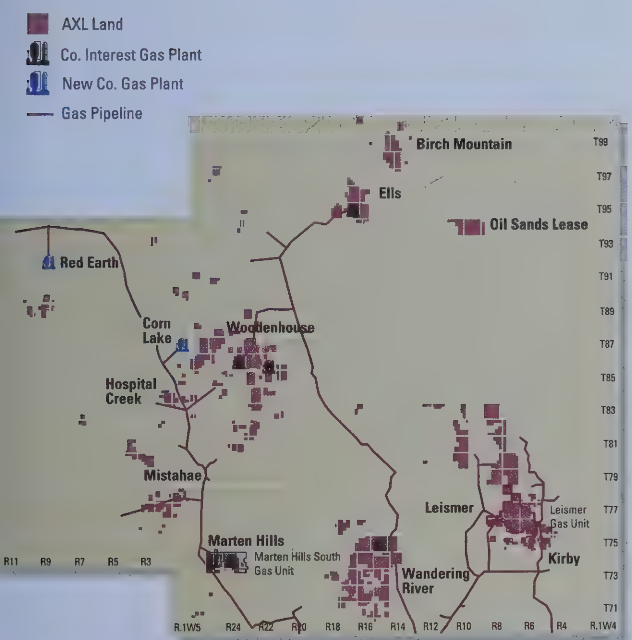
Region: SWAN HILLS/MITSUE

1997 Activity & Results

- Sales – 6,791 Bpd and 11 Mmcfd
- 2,880 net undeveloped acres acquired
- 37,875 net undeveloped acres at year end
- Drilled 22 gross (8 net) wells, resulting in 13 oil, 2 gas, 2 service and 5 dry
- Built gas plant at Jarvie

1998 Planned Activity

- Drill 6 gross (4 net) exploration wells and 28 gross (8 net) development wells
- Acquire 10.63 percent additional Swan Hills working interest, increasing interest to 30 percent
- Swan Hills activities
  - Miscible flood expansion
  - Horizontal miscible injectors
  - Jet pumping program
- Federated Pipe Lines expansion tie in



Region: NE ALBERTA

1997 Activity & Results

- Sales – 118 Mmcfd
- 93,345 net undeveloped acres acquired
- 465,460 net undeveloped acres at year end
- Drilled 79 gross (59 net) wells, resulting in 1 oil, 56 gas and 22 dry
- Participated in new facilities at Corn Lake and Red Earth
- Added compression at Woodenhouse, Kirby, Mistahae, Wandering River and Ells

1998 Planned Activity

- Drill 44 gross (26 net) exploration wells and 8 gross (5 net) development wells
- Gas gathering system expansions at Corn Lake, Woodenhouse, Kirby, Leismer, Red Earth, Hospital Creek and Wandering River

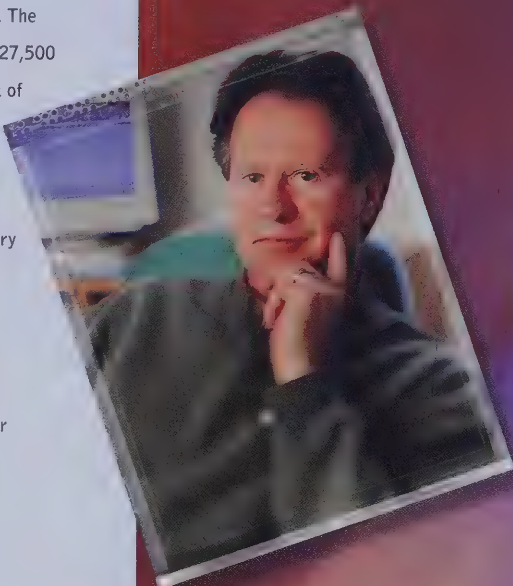
"Swan Hills Unit No. 1 in my district is Anderson Exploration's largest single oil producing property. Swan Hills is a world class oil accumulation which has produced over 550 million barrels of oil. In the past couple of years we have arrested the oil production decline rate which was being experienced. Daily oil production is now increasing. The field produces at a 92.5 percent water cut and we produce and reinject about 250,000 barrels of water per day. A lot of our efforts are concentrated on reducing water production and increasing water handling capacity which in turn permits higher oil production rates and increases oil reserves. Much of this work is initiated right here at the field level and that is satisfying."

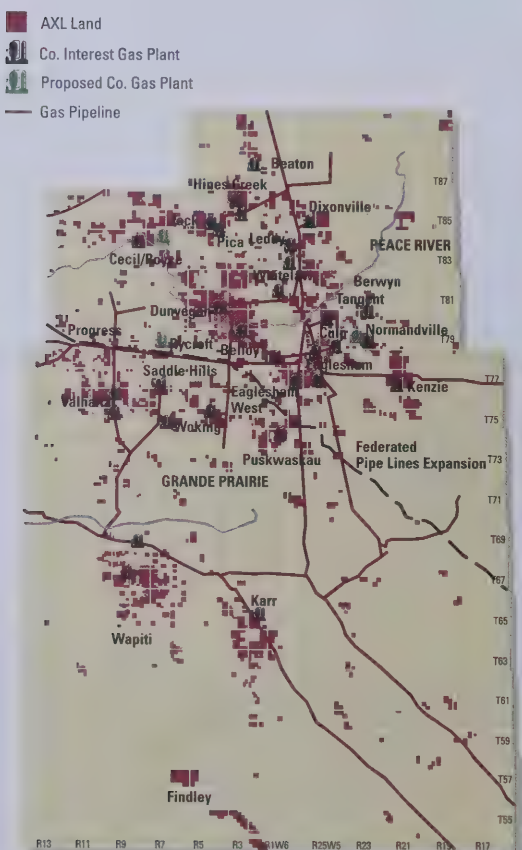
TERRY CLELLAND
District Superintendent, Swan Hills, Alberta

"The Peace River Arch area in my district is where Anderson Exploration got its start with the discovery of Dunvegan. The production we generate is from a concentrated area. At 27,500 barrels of oil equivalent per day, we provided 31 percent of the Company's sales volumes in 1997. The area is an anomaly in the north country in that it is made up primarily of low relief, gently rolling open prairie and farmland providing year-round access. The folks in Calgary continually come up with new plays to be drilled so we expect to be dealing with new production in 1998. We dominate the area with our surface infrastructure. Dunvegan liquids will be pipeline connected in 1998 by our Federated Pipe Lines expansion project, reducing our transportation costs."

RON STRANDQUIST

District Superintendent
Fairview, Alberta





Region: **PEACE RIVER ARCH**

1997 Activity & Results

- Sales – 7,509 Bpd and 200 Mmcfd
- 164,058 net undeveloped acres acquired
- 916,540 net undeveloped acres at year end
- Drilled 155 gross (75 net) wells, resulting in 68 oil, 36 gas, 25 dry and 26 service
- New facilities completed at Puskwaskau, Beaton, Hines Creek, Jack, Saddle Hills and Dunvegan

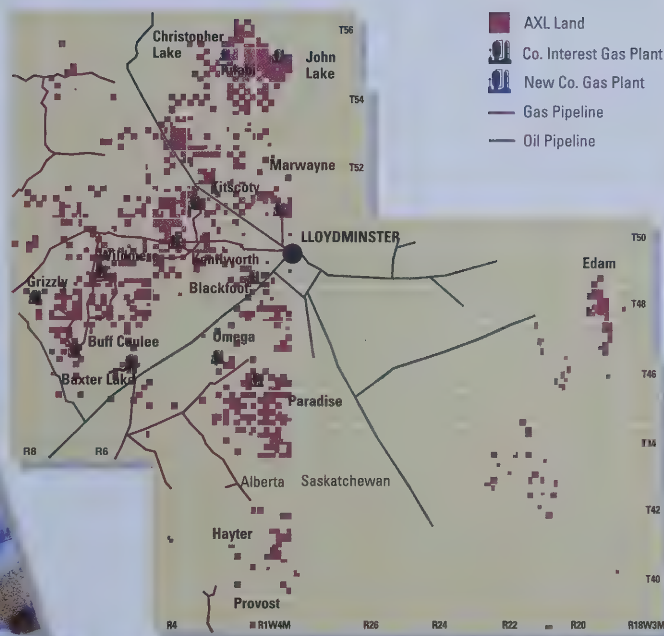
1998 Planned Activity

- Drill 73 gross (66 net) exploration wells and 121 gross (58 net) development wells
- Complete construction of new sour gas plants at Normandville and Cecil
- Construct new facilities
  Additions at Rycroft, Eaglesham and Berwyn
  Oil battery and waterflood at Dunvegan
  Waterflood at Progress
- Connect Dunvegan to Federated Pipe Lines' system

"Production in my district used to be made up primarily of shallow gas throughout the area and medium gravity oil production at Hayter. In late 1996, we acquired a heavy oil property in Saskatchewan and we began exploitation of others in Alberta. We quickly learned that operating heavy oil is a whole different ball game. Our operating costs for these properties went off scale in 1997 as we dealt with start up problems and climbed the operating learning curve. We must and are reducing these costs as we install the proper facilities and gain experience. Anderson Exploration has a number of heavy oil opportunities in the district which we want to pursue on a cost effective basis in the future."

DOUG MOORE

District Superintendent, Lloydminster, Alberta



Region: LLOYDMINSTER

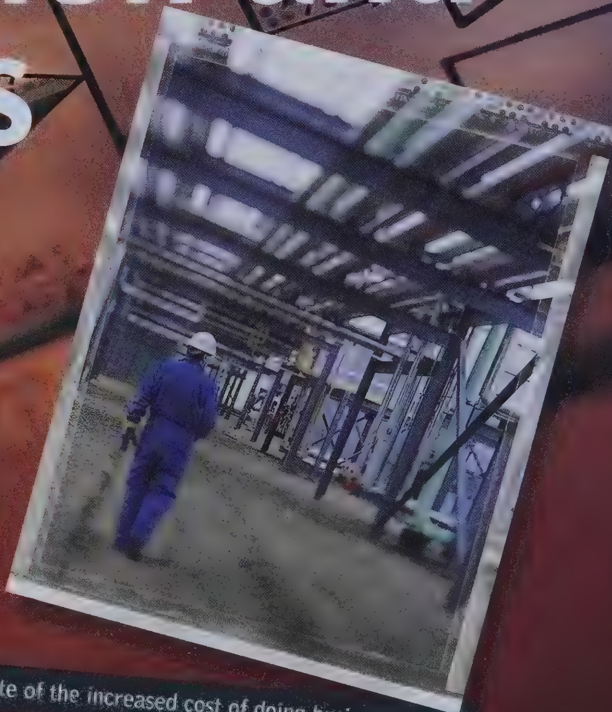
1997 Activity & Results

- Sales – 5,594 Bpd and 42 Mmcfd
- 16,412 net undeveloped acres acquired
- 217,671 net undeveloped acres at year end
- Drilled 184 gross (152 net) wells, resulting in 126 oil, 30 gas, 26 dry and 2 service
- Constructed new gas plant at Christopher Lake

1998 Planned Activity

- Drill 15 gross (15 net) exploration wells and 52 gross (52 net) development wells
- Consolidate gas surface facilities with other area operators
- Continue exploitation of heavy oil reservoirs

management's discussion and analysis



In spite of the increased cost of doing business we replaced 163% of our production and increased reserves at reasonable costs.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following discussion and analysis of financial results should be read in conjunction with the consolidated financial statements for the year ended September 30, 1997 and is based on information available at November 14, 1997. Information provided herein for fiscal 1998 is based on assumptions regarding future events and actual results may vary from these estimates.

RESULTS OF OPERATIONS

Overview

Anderson Exploration reported excellent financial results in fiscal 1997. Higher product prices, increased sales volumes and continued cost control have resulted in a 25 percent increase in cash flow from operations and an 82 percent increase in earnings. The Company spent $468.7 million on capital expenditures and finished the year with a debt to cash flow ratio of only 1.4.

Cash Flow from Operations and Earnings

(in millions of dollars, except per share amounts)

	1997	1996
Cash flow from operations:		
Canadian oil and gas operations	$ 369.9	$ 291.7
Argentina oil and gas operations*	2.8	4.2
Total oil and gas operations	372.7	295.9
Pipeline operations	10.3	10.9
Cash flow from operations	$ 383.0	$ 306.8
Cash flow from operations per share	$ 3.14	$ 2.54
Earnings:		
Canadian oil and gas operations	$ 74.7	$ 40.3
Argentina oil and gas operations*	5.5	0.1
Total oil and gas operations	80.2	40.4
Pipeline operations	7.7	7.8
Earnings	$ 87.9	$ 48.2
Earnings per share	$ 0.72	$ 0.40

* The Argentina operations were sold effective July 31, 1997, with the gain on sale being included in Argentina earnings.

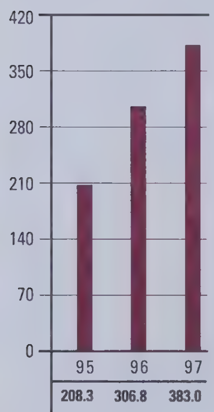
Canadian Oil and Gas Operations

In the following analysis, the components of revenue and expense are expressed on a barrel of oil equivalent basis, converting gas volumes to barrels of oil at 10 thousand cubic feet per barrel. This is a commonly used conversion ratio in the Canadian oil and gas industry, but not necessarily reflective of relative energy content or value.

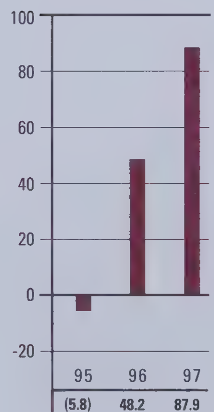
Oil and Gas Revenues

Revenues from Canadian oil and gas operations increased 25 percent to $692.1 million in 1997 from $554.6 million in 1996. The increase is due to a 13 percent increase in product prices, a 10 percent increase in sales volumes and higher revenues from straddle plant operations.

Consolidated Cash Flow from Operations
($ millions)



Consolidated Earnings
($ millions)



Components of Canadian Oil and Gas Revenues

(in millions of dollars)

	1997		1996	
Natural gas sales	$ 381.9	55%	$294.8	53%
Crude oil sales	242.4	35%	208.3	37%
NGL sales	52.4	8%	39.1	7%
Crude oil hedging gains	3.5	–	3.8	1%
Other*	11.9	2%	8.6	2%
	$ 692.1	100%	$554.6	100%

* Consists of straddle plant revenues, gains on brokered gas sales and amortization of natural gas contract settlement payments.

Natural gas sales volumes increased eight percent to 549 million cubic feet per day in 1997 from 506 million cubic feet per day in 1996. Increases in production resulted from development work done at Beaton, Dunvegan, Kirby, Puskwaskau, Red Earth and Woodenhouse and acquisitions at Wargen, Eagle and Puskwaskau. As a result of development work completed in fiscal 1997 and planned for 1998, natural gas sales volumes are expected to average 590 million cubic feet per day in 1998.

The average price for natural gas increased 20 percent to $1.91 per thousand cubic feet in 1997 from $1.59 per thousand cubic feet in 1996 due to a very cold start to the heating season in North America and record low U.S. storage levels. Prices dropped off in the last half of the year as the winter weather was short lived and followed by warmer than normal temperatures later in the year. In 1997, approximately 60 percent of the Company's natural gas was sold directly to large, credit worthy end users, marketing inter-

mediaries and local distribution companies under contracts of varying terms. These contracts include both fixed and indexed pricing arrangements. The other 40 percent of Anderson Exploration's natural gas was sold to supply aggregators. These aggregators in turn sell the gas to purchasers along gas pipelines generally at market sensitive prices, flowing back proceeds less a marketing fee to the Company. In future years, it is expected that the proportion of natural gas sold to aggregators will decrease slightly.

NGL sales volumes increased three percent to 5,669 barrels per day in 1997 compared to 5,489 barrels per day in 1996. The average price received increased 30 percent to $25.33 per barrel in 1997 compared to $19.47 per barrel in 1996. The price increase was caused by low propane and butane inventories during the year and an increased demand for condensate used to dilute heavy oil for transport. The Company sells its NGL both as NGL mix and as individual components such as propane and butane in Alberta and Ontario markets. Sales prices are indexed to major NGL market centres, such as Edmonton, Alberta. NGL sales volumes are expected to average over 7,000 barrels per day in fiscal 1998.

Canadian Oil and Gas Operations

Natural gas and NGL netbacks

(per Mcf*)

	1997	1996
Sales revenue	$ 1.96	$ 1.63
Royalties	(0.32)	(0.25)
Operating costs	(0.32)	(0.27)
Netback	$ 1.32	$ 1.11
Royalty percentage	16%	15%
Daily sales volumes		
Natural gas (Mmcfd)	549	506
NGL (Bpd)	5,669	5,489

* NGL converted to natural gas at 1 bbl = 10 mcf

Crude oil sales volumes in Canada increased 16 percent to 26,170 barrels per day in 1997 from 22,560 barrels per day in 1996. The increase in volumes is due to the development of oil discoveries at Gainsborough, development work done at Hayter and in the Lloydminster area, and the acquisition of a heavy oil property at Edam, Saskatchewan in late fiscal 1996. The increases in production were slightly lower than anticipated as a result of an unusually long spring breakup period and wet weather conditions overall. This resulted in some production being shut in longer than expected and some drilling programs being delayed. Crude oil production is expected to average over 31,000 barrels per day in fiscal 1998.

The impact of increases in world oil prices was offset to some extent by the higher proportion of heavy oil included in the Company's crude oil mix, resulting in a marginal increase in the average crude oil price in 1997. The price before hedging was $25.37 per barrel in 1997 compared to $25.22 in 1996. Hedging gains, resulting from foreign currency swap agreements, increased the price to $25.74 in 1997 compared to $25.68 in 1996. Crude oil prices are based on West Texas Intermediate prices, adjusted back to Edmonton, Alberta for quality and transportation. The acquisition of the Edam property in fiscal 1996 and development work carried out in the Lloydminster area in 1997 increased the Company's heavy oil production. However, the Company is still predominantly a light oil producer. In fiscal 1997, just under 90 percent of crude oil sales were light or medium gravity oil.

Canadian Oil and Gas Operations

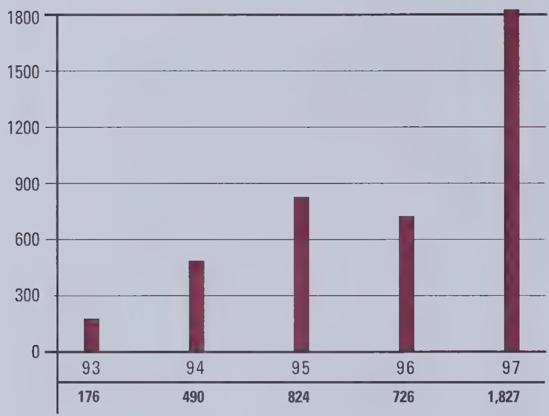
Crude oil netbacks

(per barrel)

	1997	1996
Sales revenue	$ 25.37	$ 25.22
Hedging gains	0.37	0.46
Royalties	(4.83)	(4.68)
Operating costs	(8.02)	(5.80)
Netback	$ 12.89	$ 15.20
Royalty percentage	19%	19%
Daily sales volumes (Bpd)	26,170	22,560

Other oil and gas revenue was $11.9 million in 1997 compared to $8.6 million in 1996. Revenues from straddle plant operations increased by $5.7 million as a second plant commenced operations in fiscal 1997. This increase was partially offset by reductions in brokered gas sales revenue, as the Company used more of its own production and less purchased gas to meet sales commitments.

Canadian Oil and Gas Operations
Straddle Plant NGL Sales Volumes
(Bpd)



Royalties

Canadian oil and gas royalties, net of the Alberta Royalty Tax Credit (ARTC), increased 31 percent to $115.9 million in 1997 from $88.4 million in 1996, consistent with the increase in revenues. Royalties were 17 percent of oil and natural gas revenue in 1997 compared to 16 percent in 1996. In 1997, royalties were reduced by $10.7 million for an adjustment to Alberta gas Crown royalties as a result of final invoices received under the Alberta royalty simplification program related to 1994, 1995 and 1996. Without the refund, royalties would have been 18 percent of revenue in 1997. The increased royalty rate is the result of the higher product prices received during the year. On a barrel equivalent basis, royalties increased 19 percent to $3.66 in 1997 from $3.07 in 1996. ARTC was $1.2 million in 1997 compared to $1.5 million in 1996.

Royalties are sensitive to producing rates and, in Alberta, are based on reference prices established by the government. Royalty rates are not expected to change significantly in fiscal 1998.

Operating Expenses

Canadian oil and gas operating costs were $147.0 million in 1997 compared to $103.7 million in 1996. On a barrel equivalent basis, operating costs increased 29 percent to $4.64 in 1997 compared to $3.60 in 1996. Increased activity in the industry has resulted in overall increases in the cost of services and equipment. In addition, operating costs associated with the Company's new heavy oil production were very high in the year due to substantial start up costs and sand hauling and disposal costs. The increase in crude oil operating costs from $5.80 per barrel of oil equivalent in 1996 to $8.02 in 1997 is largely due to costs associated with the new heavy oil production. Heavy oil amounted to 10 percent of total oil production in 1997 versus two percent in 1996. Heavy oil operating costs on a per barrel basis are expected to decrease in 1998, however, the proportion of heavy oil to total crude oil production is expected to increase. Considering both increases in costs due to continued high levels of industry activity and decreases in costs due to expected efficiencies to be gained in heavy oil, it is anticipated that 1998 oil and gas operating expenses will be similar to 1997 on a barrel equivalent basis.

Other Revenue

Other revenue related to Canadian oil and gas operations was $9.1 million in 1997 compared to $3.3 million in 1996. In 1997, the major components of other revenue were interest of $6.3 million related to prior year tax refunds and a gain of $2.5 million on the sale of a portfolio investment. In 1996, the major components of other revenue were gains on the sale of the aviation division and rail tank cars.

General and Administrative Expenses

Canadian oil and gas general and administrative expenses were $25.7 million in 1997 compared to $24.3 million in 1996. On a barrel equivalent basis, general and administrative expenses declined by five percent to $0.81 in 1997 compared to $0.85 in 1996. Increases in activity have resulted in higher staff levels and higher associated salary costs. These increases were partially offset by larger operator recoveries, also the result of more activity. General and administrative expenses included a $4.3 million recovery of pension costs in 1997 compared to a $2.7 million recovery in 1996. The recovery results from the amortization of experience gains and, in 1997, a settlement gain on the purchase of annuity contracts in respect of all retired and deferred vested members of the registered pension plan. The purchase of the annuity contracts was a funding decision that essentially eliminated the Company's exposure to future changes in the value of the pension assets available to meet the pension obligations associated with those members of the plan. The pension adjustment is a non-cash recovery. Pension amounts funded in the year were $0.5 million. General and administrative expenses on a cash basis, after adjusting for

these pension amounts, were $0.98 per barrel of oil equivalent compared to $0.92 in 1996. Large pension adjustments are not expected in future years. The Company expects that, on a cash basis, 1998 general and administrative expenses per barrel of oil equivalent will be similar to 1997.

Canadian Oil and Gas Operations

General and administrative expense
(in millions of dollars)

	1997	1996
Gross expense	$ 41.1	$ 37.5
Operator recoveries	(15.4)	(13.2)
Net expense	$ 25.7	$ 24.3

(average cost per BOE)	1997	1996
Gross expense	$ 1.30	$ 1.31
Operator recoveries	(0.49)	(0.46)
Net expense	$ 0.81	$ 0.85

The Company does not capitalize any general and administrative expenses, except to the extent of the Company's working interest in operated capital expenditure programs where overhead fees have been charged to third parties. The Company does not charge overhead fees on 100 percent owned projects. The Company also does not capitalize the salaries and other expenses of its exploration department as direct capital expenditures. This allows readers of the consolidated financial statements to assess the Company's true administrative expenditures.

Interest Expense

Interest expense related to Canadian oil and gas operations was $33.1 million in 1997 compared to $39.8 million in 1996. On a barrel equivalent basis, interest expense decreased by 24 percent to $1.05 in 1997 from $1.38 in 1996. The decrease was due to lower interest rates. Over the course of the year, the Company fixed the interest rates on a significant portion of its bank debt through interest rate swap agreements. At the end of the year, approximately 24 percent of the Company's bank debt was still subject to floating interest rates. The Company did not capitalize any interest related to its oil and gas operations in 1997 or 1996. Debt balances increased over the last half of the year as a result of the Company's active drilling, construction and acquisitions program. Interest expense is expected to increase in fiscal 1998 as a result of the higher debt levels.

Current Taxes

Current taxes related to Canadian oil and gas operations were $1.8 million in 1997 compared to $5.6 million in 1996. On a barrel equivalent basis, these taxes were $0.06 in 1997 compared to $0.19 in 1996. Current taxes consist of the federal large corporations tax, provincial capital taxes and provincial resource surcharges. During the year, a settlement was reached with Revenue Canada for prior year reassessments that related primarily to the calculation of resource allowance. A refund of $4.7 million reduced the Company's 1997 current tax provision. Refund interest of $6.3 million related to this settlement was recorded as other income. Canadian oil and gas operations are not expected to be currently taxable in 1998, except for the large corporations tax, provincial capital taxes and provincial resource surcharges.

The Company has approximately $744 million in unused tax pools related to its Canadian oil and gas operations. A portion of these tax pools are successored as pools acquired in corporate acquisitions are generally dedicated to sheltering the income from properties held by an acquired company at the time of the acquisition.

Cash Flow From Operations

Cash flow from Canadian oil and gas operations was $369.9 million in 1997 compared to $291.7 million in 1996. On a barrel equivalent basis, this represents $11.68 in 1997 compared to $10.13 in 1996. The Company's cash flow is discretionary and available for capital programs and reduction of long term obligations.

Cash Flow from Canadian Oil and Gas Operations
($ per barrel equivalent)

	1997	1996
Oil and gas revenues	$ 21.86	$ 19.26
Royalties	(3.66)	(3.07)
Operating costs	(4.64)	(3.60)
	13.56	12.59
Other revenues	0.21	0.03
General and administrative expenditures	(0.98)	(0.92)
Interest	(1.05)	(1.38)
Current taxes	(0.06)	(0.19)
Cash flow from operations	$ 11.68	$ 10.13

Depletion and Depreciation

Depletion and depreciation provided on the unit of production method is based on total proven reserves with conversion of natural gas to oil using their relative energy content. The provision for depletion and depreciation on Canadian oil and gas properties increased 10 percent to $234.4 million in 1997 compared to $212.1 million in 1996, consistent with increases in production. On a barrel equivalent basis, the provision was $7.40, which was similar to 1996. In 1998, depletion and depreciation expense is expected to increase as result of increases in production. However, the rate per barrel of oil equivalent should be similar to 1997.

Future Site Restoration

The Company provided $10.2 million for future site restoration related to its Canadian oil and gas operations in 1997 compared to $9.7 million in 1996. On a barrel equivalent basis, this charge amounted to $0.32 in 1997 and $0.34 in 1996. It is anticipated that the future site restoration provision will increase in 1998 as a result of increased production. However, the rate per barrel of oil equivalent is not expected to increase.

Deferred Taxes

Deferred tax expense on Canadian oil and gas operations was $58.4 million or $1.84 per barrel of oil equivalent in 1997 compared to $33.9 million or $1.18 per barrel of oil equivalent in 1996. The total tax provision was $60.1 million in 1997 compared to $39.5 million in 1996. The total tax provision as a percentage of pre-tax income was 44.6 percent compared to 49.5 percent in 1996. The decrease in the percentage is largely due to the refund related to prior year tax reassessments. In addition, the relatively fixed levels of non-deductible depletion included in pre-tax earnings and large corporations tax included in current tax expense are not affected by earnings levels.

Earnings

Earnings from Canadian oil and gas operations increased to $74.7 million in 1997 from $40.3 million in 1996. On a barrel equivalent basis, earnings were $2.36 in 1997 compared to $1.40 in 1996. The increase is attributable to higher product prices, higher production levels and the refunds received for royalty and tax reassessments.

Earnings from Canadian Oil and Gas Operations
($ per barrel equivalent)

	1997	1996
Cash flow from operations	$ 11.68	$ 10.13
Depletion and depreciation	(7.40)	(7.37)
Future site restoration	(0.32)	(0.34)
Deferred taxes	(1.84)	(1.18)
Other*	0.24	0.16
Earnings	$ 2.36	$ 1.40

* Consists of the non-cash pension recovery and gains on sale of assets.

Argentina Oil and Gas Operations

Effective July 31, 1997, the Company sold its investment in Home Oil International Ltd., a wholly-owned subsidiary that conducted oil and gas exploration, development and production activities in Argentina. Crude oil sales to the effective date of the sale averaged 1,563 barrels per day in 1997 compared to 1,537 barrels per day in fiscal 1996. The contribution to the Company's annualized average crude oil sales was 1,302 barrels per day in fiscal 1997.

Cash flow from the Argentina operations was $2.8 million for the 10 months ended July 31, 1997 compared to $4.2 million for the year ended September 30, 1996. Excluding the gain on sale, the Argentina operations reported a loss of $0.5 million in 1997 compared to nil in 1996. Operating and general and administrative costs were higher than in Canada, averaging $7.91 and $4.10 respectively per barrel of oil equivalent in 1997.

Proceeds on the sale of the subsidiary were $50.4 million, net of selling costs and cash sold. A gain of $8.0 million ($6.0 million after tax) was recorded on the sale.

Pipeline Operations

The Company's pipeline transportation activities are conducted through its 50 percent interest in Federated Pipe Lines. The Company accounts for its interest in Federated Pipe Lines using the proportionate consolidation method, whereby the Company's proportionate share of the assets, liabilities, revenues and expenses are included in its consolidated financial statements.

Cash flow from pipeline operations was $10.3 million in 1997 compared to $10.9 million in 1996. Earnings were $7.7 million in 1997 compared to $7.8 million in 1996. The slight decline in cash flow from operations and earnings is due to a toll reduction on one of the lines and higher maintenance costs incurred in fiscal 1997.

Construction of a major expansion to the pipeline system started in the third quarter of fiscal 1997 and is scheduled for completion in the spring of 1998 with deliveries starting shortly thereafter. The total cost is expected to be approximately $110.0 million, of which $36.0 million had been spent to September 30, 1997. The expansion is being funded with Federated Pipe Lines cash flow and bank debt. The Company's share of construction costs is 50 percent.

CAPITAL EXPENDITURES

Net capital expenditures were $468.7 million in 1997 compared to $247.4 million in 1996. The Company replaced 163 percent of its production with proven reserves, after revisions, and increased its non-producing land inventory.

The Company completed several acquisitions of producing and exploratory properties during the year. The largest of these transactions involved the purchase of six properties from a single vendor in the second quarter. The acquisition was strategic as Anderson Exploration increased its working interest in four properties already operated by the Company at East Eagle, West Eagle, Puskwaskau and Swan Hills and purchased offsetting operating interests at Birley/Wargen.

The 1997 capital expenditure program was funded by cash flow from operations, the sale of the Company's operations in Argentina and increases in bank debt.

Net Capital Expenditures

(in millions of dollars)

	1997	1996
Exploration drilling and completion	$ 71.5	$ 43.6
Seismic	17.5	6.3
	89.0	49.9
Development drilling, completion and recompletion	111.1	57.3
Plant and production facilities	123.0	51.2
	234.1	108.5
Land acquisition and retention	47.3	29.0
Property acquisitions	72.3	52.3
Argentina	6.0	3.3
Straddle plant	–	5.7
Miscible fluids	(0.9)	1.4
Pipeline	19.8	1.5
Corporate	3.5	4.4
Gross capital expenditures	471.1	256.0
Proceeds on disposition of properties*	(2.4)	(8.6)
Net capital expenditures	$ 468.7	$ 247.4

* Excludes the sale of the Company's operations in Argentina.

Net capital expenditures are budgeted to be $505 million in 1998. This amount includes $98 million for the purchase of an additional 10.63 percent working interest in Swan Hills Unit No. 1 on October 6, 1997 and $37 million for the Company's share of pipeline expenditures, largely related to construction of the Federated NGL North project. Approximately 37 percent of the remaining budget is expected to be spent on exploration and land. Approximately 57 percent of the remaining budget is expected to be spent on gas projects.

Finding and Development Costs

	1997	1996
Net capital expenditures ($ millions)	$ 468.7	$ 247.4
Less pipeline and straddle plant expenditures	(19.8)	(7.2)
	448.9	240.2
Site restoration expenditures	3.8	1.6
Proceeds on sale of Argentina operations, net of working capital and other obligations	(47.1)	–
	$ 405.6	$ 241.8
Reserve additions before revisions (million barrels equivalent)		
Proven	51.2	35.9
Proven plus 1/2 probable	62.5	42.6
Reserve additions after revisions (million barrels equivalent)		
Proven	52.3	36.5
Proven plus 1/2 probable	60.4	34.1
Finding and development costs before revisions ($ per barrel equivalent)		
Proven	$ 7.92	$ 6.74
Proven plus 1/2 probable	$ 6.49	$ 5.67
Finding and development costs after revisions ($ per barrel equivalent)		
Proven	$ 7.75	$ 6.63
Proven plus 1/2 probable	$ 6.71	$ 7.09

FINANCIAL RESOURCES AND LIQUIDITY

The Company's financial obligations increased by $25.3 million in fiscal 1997. Long term debt increased from $512.7 million at September 30, 1996 to $545.0 million at September 30, 1997 while the net working capital deficiency decreased from $19.2 million to $12.2 million. The increase in financial obligations was due to net capital expenditures and site restoration expenditures in excess of cash flow from operations and other proceeds. Net capital expenditures of $468.7 million and site restoration expenditures of $3.8 million represented 123 percent of cash flow from operations. The sale of the Argentina operations resulted in proceeds of $47.1 million, net of working capital and other obligations. The sale of other investments resulted in proceeds of $5.3 million. Proceeds of $16.8 million were received on the issue of common shares under employee stock savings plans and stock option plans. Other long term obligations were reduced by $5.0 million.

During the year, the Company renegotiated the terms of a significant portion of its existing bank facilities, essentially combining two facilities into one larger syndicated facility. The Company also entered into new interest rate swap agreements that effectively fixed the interest rate on a significant portion of outstanding long term debt. The terms of the new bank facility and the interest rate swaps are described in the notes to the consolidated financial statements. At September 30, 1997, the Company had unused long term and operating lines of credit of $243.8 million. The $98 million acquisition of the additional interest in Swan Hills in October 1997 was funded out of these unused lines. Sinking fund payments of $0.9 million are the only long term debt repayments required to be made in fiscal 1998 and this amount has been included in the working capital deficiency noted above.

Cash flow from operations covered interest expense 11.7 times in 1997 compared to 8.4 times in 1996. Long term debt was 1.4 times 1997 cash flow from operations compared to 1.7 in 1996. In 1998, capital expenditures are expected to be higher than cash flow from operations and other sources of cash. An increase in long term debt is expected, but the ratio of long term debt to cash flow is still expected to remain under 2.0.

Share Price

	1993	1994	1995	1996	1997				
	Year	Year	Year	Year	Q1	Q2	Q3	Q4	Year
High	17.50	18.00	16.25	15.25	18.80	20.25	19.30	18.60	20.25
Low	5.75	12.13	10.75	11.62	13.70	15.20	15.15	16.60	13.70
Close	16.50	15.38	12.63	13.70	17.70	16.80	17.80	17.20	17.20
Volume (000)	45,814	30,522	87,095	87,963	32,360	27,587	19,853	27,897	107,697

SHARE INFORMATION

The Company's common shares were listed for trading on The Toronto Stock Exchange on July 12, 1988. At September 30, 1997, there were 122,360,963 common shares outstanding. During 1997, 1,335,876 common shares were issued for proceeds of $16.8 million under the employee stock option and stock savings plans. These plans encourage employee participation in Company ownership. The Company's market capitalization at September 30, 1997 was $2.1 billion.

BUSINESS RISKS

Crude oil and natural gas exploration, production and marketing operations involve a number of business risks. These include the uncertainty of finding new reserves and the instability of commodity prices. These risks are compensated for by employing highly competent professional staff and utilizing equity and cash flow from operations to fund a significant portion of capital expenditures so that debt does not become a burden.

The Company generates its exploration prospects internally. Extensive geological, geophysical, engineering and environmental analyses are performed before committing to the drilling of new prospects. These analyses are used to ensure a suitable balance between risk and reward.

Commodity prices are influenced by supply and demand, both locally and worldwide, competition, the U.S. dollar exchange rate, transportation, political stability and seasonal changes in demand resulting from weather patterns in the Company's marketing areas. The value of the Canadian dollar, which is influenced by economic and political factors, affects all of the Company's crude oil sales and, in fiscal 1998, approximately one third of its natural gas sales which are priced in U.S. dollars. To reduce the impact of these factors, the Company maintains a balanced portfolio of sales contracts and, in the past, has entered into hedging contracts. Hedging contracts are subject to approval by the Board of Directors. Anderson Exploration's current policy is that it will not hedge crude oil or natural gas prices. The Company does enter into physical contracts for the sale of natural gas at fixed prices and terms. It has also fixed the heavy/light differential for heavy oil volumes at Edam, Saskatchewan under a marketing arrangement.

The Company has fixed the rate of interest on approximately 76 percent of its long term debt obligations. In 1996 and 1997, the Company fixed the rate of interest on $200.0 million of its outstanding bank loans through swap agreements at an average rate of 6.77 percent. The agreements mature at various dates between 2001 and 2007. The Company has fixed the rate of interest on its $200.0 million oil indexed debentures at 8.26 percent to their maturity on October 31, 2000, also through the use of swap agreements. In addition, the Company, through its 50 percent ownership of Federated Pipe Lines, has $12.6 million of sinking fund debentures outstanding which bear interest at a fixed rate of 9.54 percent. Subsequent to year end, the Company fixed the rate of interest on $53.0 million of additional bank loans at 4.43 percent for one year. The additional bank loans were part of the funds borrowed to finance the acquisition of the additional interest in Swan Hills.

Historically, regulatory issues and taxation have had a significant impact on the oil and natural gas industry. However, with the deregulation of the industry beginning in 1985 and stable taxation levels, there is currently a reasonable operating environment in Canada for financially healthy companies. The potential exists for this environment to change due to changes in taxation and energy policy.

The industry is subject to extensive regulations imposed by governments related to the protection of the environment. Environmental legislation in Western Canada has undergone major revisions. Environmental standards and compliance are more stringent. The Company is committed to meeting its responsibilities to protect the environment wherever it operates and has instituted a series of controls and procedures with respect to environmental protection. The estimated liability for future abandonment and restoration costs is reviewed annually and is recorded in accordance with CICA recommendations. Total future costs are estimated to be $153.7 million, of which $43.2 million has been recorded as a liability.

SENSITIVITIES

The Company's earnings and cash flow from operations are highly sensitive to changes in factors that are beyond its control. An estimate of the Company's sensitivities to changes in commodity prices, exchange rates and interest rates is summarized below.

	Cash Flow		Earnings	
	$ millions	$/share	$ millions	$/share
Change of $0.10/Mcf in the price of natural gas	17.0	0.14	11.0	0.09
Change of $US 1.00/bbl in the WTI crude oil price	12.0	0.10	8.0	0.06
Change of $US 0.01 in the U.S./Canada exchange rate	5.0	0.04	3.0	0.02
Change of 1% in interest rates	3.0	0.02	2.0	0.01

YEAR 2000

Anderson Exploration has begun the process of looking at its computer systems to assess potential problems and costs associated with the year 2000. The problem revolves around the fact that many computer systems and software applications have been designed to recognize dates using only the last two digits of the year. In the year 2000, it is anticipated that many systems and programs will not function properly. On a worldwide basis, the costs of dealing with the problem are expected to be several billion dollars.

During the year, the Company formed a task force to catalogue the items to be addressed. This process is 90 percent complete. Five major areas have been identified for review, including: (1) financial and technical systems, networks and data exchanges; (2) field production systems and processes; (3) pipeline control systems; (4) office security systems, telephone systems and equipment; and (5) exploration mapping. The Company completed a significant computer systems conversion project during the year and all of its new financial accounting, production accounting and land systems have warranties with respect to the year 2000. These systems will still be tested, along with the other systems, over the next several months. Testing in the field may be done during plant turnarounds. Anderson Exploration hopes to complete its testing and other due diligence work sometime in calendar 1998. All costs associated with the project will be expensed as incurred. These costs are not expected to have a material effect on the financial results of the Company.

BUSINESS PROSPECTS

Approximately 68 percent of the Company's remaining proven reserves are natural gas and natural gas liquids. With the sale of the Argentina operations, the Company now operates exclusively in western Canada.

Natural gas prices are affected by a number of factors including weather and storage levels in the U.S. and Canada. A cold start to the winter and record low U.S. storage levels produced some exceptionally strong prices in December 1996 and January 1997. Prices fell off when a warmer than normal winter set in. Current U.S. storage levels are higher than in 1996 but still below average. In Alberta, an additional 300 million cubic feet per day of export capacity added by TCPL in November 1997 should match increases in deliverability. The impact that weather patterns will have on prices remains to be seen. The Company is partially protected from price fluctuations as approximately 159 million cubic feet per day of its 1998 natural gas sales are subject to fixed price contracts at an average plantgate price of $2.00 per thousand cubic feet. In November 1998, when the Northern Border and TCPL expansion projects are slated to be completed, the industry should see significant reduction in the differential between U.S. and Alberta prices.

In fiscal 1997, crude oil prices exceeded expectations as the delayed resumption of Iraqi oil exports, higher than anticipated demand and low refinery inventories resulted in an average WTI price of $US 21.76 per barrel. Iraqi oil exports are expected to continue in fiscal 1998, although volumes may be erratic. While increases in supply are expected, world wide demand is also expected to increase as many of the world's major economies exhibit solid growth. The recent weaknesses in southeast Asian economies create some uncertainty surrounding economic growth in that region.

The increasing supply of heavy oil in Canada is expected to cause the heavy/light differential to increase from the fiscal 1997 average of approximately $US 4.50 per barrel. The differential for the Company's volumes at Edam, its most significant heavy oil area, is capped under a marketing arrangement. Thus, our exposure to a widening heavy/light differential in fiscal 1998 is limited. Heavy oil is expected to make up 13 percent of our total crude oil production in fiscal 1998.

The Company's capital budget for fiscal 1998 is $505 million. This includes approximately $98 million already spent for the acquisition of an additional 10.63 percent interest in Swan Hills Unit No. 1, increasing the Company's operating interest in that major oil property to 30 percent. The 1998 exploration budget contemplates the drilling of over 180 wells. Exploration expenditures will be directed 60 percent towards gas prospects and 40 percent towards oil prospects. Over 60 percent of the drilling activities are expected to take place in the first half of the year. The Company's exploration program will focus on medium risk projects. It is expected that our exploration program will shift towards higher risk/reward projects over the next few years. The 1998 development budget contemplates the drilling of over 380 wells. Gas projects are expected to account for 62 percent of the development budget.

In the last year, the industry has experienced significant increases in activity levels. This has resulted in a shortage of services and higher costs, reflected in the higher finding and development and operating costs reported throughout the industry this year. It is expected that these conditions will persist in fiscal 1998 and that industry costs for undeveloped land, wages, services and equipment will continue to increase. In fiscal 1997, the Company reported higher finding and development costs on a barrel equivalent basis but also reported higher netbacks from operations. Anderson Exploration has proven it can operate successfully in the current environment, setting realistic targets for production growth and investing its resources wisely to maximize shareholder value.

MANAGEMENT'S REPORT

Management is responsible for the preparation of the consolidated financial statements and the consistent presentation of all other financial information in this annual report.

Management maintains a system of internal controls to provide reasonable assurance that assets are safeguarded and that relevant and reliable financial information is produced in a timely manner.

External auditors, appointed by the shareholders, have examined the consolidated financial statements. Their report is presented below. The Audit Committee of the Board of Directors has reviewed the consolidated financial statements with management and the external auditors. The Board of Directors has approved the consolidated financial statements on the recommendation of the Audit Committee.

J.C. Anderson

J.C. Anderson
Chairman & Chief Executive Officer
November 19, 1997

D.G. Scobie

David G. Scobie
Senior Vice President & Chief Financial Officer

AUDITORS' REPORT TO THE SHAREHOLDERS

We have audited the consolidated balance sheets of Anderson Exploration Ltd. as at September 30, 1997 and 1996 and the consolidated statements of earnings, retained earnings and changes in financial position for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at September 30, 1997 and 1996 and the results of its operations and the changes in its financial position for the years then ended in accordance with generally accepted accounting principles.

KPMG

Chartered Accountants
Calgary, Canada
November 14, 1997

CONSOLIDATED BALANCE SHEETS

September 30 (stated in thousands of dollars)	1997	1996
Assets		
Current assets		
Accounts receivable	$ 129,178	$ 87,318
Inventories	9,436	7,716
	138,614	95,034
Property, plant and equipment (note 2)	2,163,625	1,974,235
Other assets	619	3,982
	$ 2,302,858	$ 2,073,251
Liabilities and Shareholders' Equity		
Current liabilities		
Bank indebtedness, unsecured	$ 12,634	$ 8,774
Accounts payable and accrued liabilities	133,364	100,343
Current portion of deferred revenue	3,935	4,252
Current portion of long term debt	900	900
	150,833	114,269
Long term debt (note 3)	544,982	512,767
Other credits (note 4)	64,399	68,490
Deferred taxes	556,573	496,403
	1,316,787	1,191,929
Shareholders' equity		
Share capital (note 5)	736,388	719,582
Retained earnings	249,683	161,740
	986,071	881,322
Subsequent event (note 12)		
	$ 2,302,858	$ 2,073,251

See accompanying notes to consolidated financial statements.

On behalf of the Board:

J.C. Anderson

Director

Director

CONSOLIDATED STATEMENTS OF EARNINGS

Years ended September 30 (stated in thousands of dollars, except per share amounts)	1997	1996
Revenues		
Oil and gas	$ 705,105	$ 569,317
Royalties, net of ARTC of $1,227 (1996 – $1,475)	(118,407)	(91,173)
Pipeline	27,428	27,970
Other	17,514	3,346
	631,640	509,460
Expenses		
Operating	159,617	117,407
Depletion and depreciation	240,714	219,574
General and administrative	28,304	27,068
Interest (including $34,542 on long term debt; 1996 – $39,554)	35,954	41,437
Future site restoration	10,397	10,009
	474,986	415,495
Earnings before taxes	156,654	93,965
Taxes (note 7)		
Current	8,541	12,301
Deferred	60,170	33,461
	68,711	45,762
Earnings	$ 87,943	$ 48,203
Earnings per common share (note 6)		
Basic	$ 0.72	$ 0.40
Fully diluted	$ 0.71	$ 0.40
Weighted average number of common shares outstanding (thousands)	121,873	120,773

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

Years ended September 30 (stated in thousands of dollars)	1997	1996
Retained earnings, beginning of year	$ 161,740	$ 113,537
Earnings	87,943	48,203
Retained earnings, end of year	$ 249,683	$ 161,740

See accompanying notes to consolidated financial statements.

Years ended September 30
(stated in thousands of dollars, except per share amounts)

	1997	1996
Cash provided by (used in):		
Operations		
Earnings	$ 87,943	$ 48,203
Add (deduct) non-cash items:		
Depletion and depreciation	240,714	219,574
Future site restoration	10,397	10,009
Deferred taxes	60,170	33,461
Gain on sale of investments (note 8)	(10,547)	–
Other	(5,632)	(4,487)
Cash flow from operations	383,045	306,760
Decrease in deferred revenue	(3,701)	(4,086)
Change in non-cash working capital related to operations	(17,202)	(25,286)
Change in other liabilities related to operations	(2,000)	(3,300)
	360,142	274,088
Investments		
Additions to property, plant and equipment, net	(468,744)	(247,376)
Proceeds on sale of Home Oil International Ltd. (note 8)	50,417	–
Proceeds on sale of other investments (note 8)	5,323	–
Site restoration expenditures	(3,760)	(1,573)
Change in non-cash working capital related to investments	3,484	19,577
Other	535	375
	(412,745)	(228,997)
Financing		
Increase (decrease) in long term debt	32,215	(48,550)
Issue of common shares	16,806	5,085
Change in non-cash working capital related to financing	(278)	1,114
	48,743	(42,351)
Increase (decrease) in cash	(3,860)	2,740
Cash (deficiency), beginning of year	(8,774)	(11,514)
Cash (deficiency), end of year	$ (12,634)	$ (8,774)
Cash flow from operations per common share (note 6):		
Basic	$ 3.14	$ 2.54
Fully diluted	$ 3.04	$ 2.48
Change in non-cash working capital:		
Accounts receivable	$ (41,860)	$ (25,637)
Inventories	(1,720)	4,575
Accounts payable and accrued liabilities	33,021	16,467
Disposition of non-cash working capital	(3,437)	–
	$ (13,996)	$ (4,595)

Cash (deficiency) includes cash plus current bank indebtedness.
See accompanying notes to consolidated financial statements.

Years ended September 30, 1997 and 1996
(Tabular amounts in thousands of dollars, unless otherwise stated)

Anderson Exploration Ltd. ("Anderson Exploration" or "the Company") is engaged in the acquisition, exploration, development, production and pipeline transportation of petroleum and natural gas resources, primarily in western Canada. The consolidated financial statements have been prepared in accordance with generally accepted accounting principles in Canada.

1. Significant accounting policies:

(a) Consolidation

The consolidated financial statements include the accounts of Anderson Exploration, its wholly owned subsidiaries and its 50 percent interest in Federated Pipe Lines Ltd. ("Federated"), a pipeline transportation company. The Company's interest in Federated is accounted for using the proportionate consolidation method, whereby the Company's proportionate share of the assets, liabilities, revenues and expenses are included in the consolidated financial statements.

(b) Joint interest operations

A significant proportion of the Company's petroleum and natural gas exploration, development and production activities are conducted with others and accordingly the accounts reflect only the Company's proportionate interest in such activities.

(c) Inventories

Inventories are stated at the lower of cost and net realizable value. Cost is determined using the specific item or average cost method.

(d) Property, plant and equipment

The Company follows the full cost method of accounting for petroleum and natural gas properties. Under this method, all costs relative to the exploration for and development of petroleum and natural gas reserves are capitalized into cost centres on a country by country basis. Capitalized costs include lease acquisitions, geological and geophysical costs, lease rentals on non-producing properties, costs of drilling productive and non-productive wells and plant and production equipment costs. General and administrative expenses are not capitalized other than to the extent of the Company's working interest in Company operated capital expenditure programs to which overhead fees have been charged under standard industry operating agreements. Overhead fees are not charged on 100 percent owned projects. Proceeds received from disposals of properties and equipment are credited against capitalized costs unless the disposal would alter the rate of depletion and depreciation by more than 20 percent, in which case a gain or loss on disposal is recorded.

Depletion of petroleum and natural gas properties and depreciation of plant and production equipment are provided on the unit of production method based on total proven reserves before royalties as estimated by Company engineers. Natural gas sales and reserves are converted to equivalent units of crude oil using their relative energy content. Pipelines, buildings and other equipment are depreciated over their useful lives using the declining balance and straight line methods at rates varying from 5 percent to 40 percent per annum.

The Company applies a ceiling test to capitalized petroleum and natural gas property costs to ensure that such costs do not exceed the estimated future net revenues from production of proven reserves, at prices and operating costs in effect at the year end, plus the cost of unevaluated properties less management's estimate of impairment. The test also provides for estimated future administrative overhead, financing costs, future site restoration costs and taxes.

(e) Future site restoration costs

Provisions for future site restoration costs are made over the life of the Company's petroleum and natural gas properties using the unit of production method. Costs are based on engineering estimates considering current regulations, costs and industry standards. Actual expenditures incurred are applied against deferred future site restoration costs.

(f) Revenue recognition

Revenue from the sale of petroleum and natural gas is recognized when deliveries of products are made, with payments received under prepaid gas contracts being taken into income on the ultimate delivery of the natural gas.

Settlement payments received for restructuring or terminating long term natural gas sales contracts are recognized as revenue over the remaining period of the contracts or over the life of the reserves associated with the contracts.

(g) Foreign currency translation

Monetary assets and liabilities denominated in a foreign currency are translated at the rate of exchange in effect at year end while non-monetary assets and liabilities are translated at historical rates of exchange. Revenues and expenses are translated at monthly average rates of exchange. Translation gains and losses are included in earnings except for unrealized gains and losses on long term monetary items which are deferred and amortized to earnings over their remaining term.

(h) Hedging

Financial instruments are used to manage exposures related to interest rates, the Canada/U.S. exchange rate and petroleum and natural gas prices. They are not used for trading purposes.

Amounts received or paid under interest rate swaps are recognized in interest expense on an accrual basis, while gains and losses on exchange rate and price hedges are included in revenue on the sale of the related production.

2. Property, plant and equipment:

	1997		1996	
	Cost	Accumulated depletion and depreciation	Cost	Accumulated depletion and depreciation
Petroleum and natural gas properties, including plant and production equipment				
Canada	$ 4,010,702	$ (1,919,474)	$ 3,571,150	$ (1,689,311)
Argentina	–	–	41,428	(5,240)
Pipelines	99,085	(47,037)	78,354	(43,330)
Buildings, land and other	60,093	(39,744)	56,733	(35,549)
	$ 4,169,880	$ (2,006,255)	$ 3,747,665	$ (1,773,430)
Net book value		$ 2,163,625		$ 1,974,235

At September 30, 1997, petroleum and natural gas properties included $141,500,000 (1996 – $95,100,000) relating to unproved properties in Canada which have been excluded from depletion and depreciation calculations. At September 30, 1996, an additional $5,088,000 relating to unproved properties in Argentina was also excluded. Future development costs of proven undeveloped reserves of $254,033,000 are included in depletion and depreciation calculations.

At September 30, 1997, the Company had a surplus in its ceiling test. The prices used in the ceiling test evaluation were as follows:

Natural gas (per thousand cubic feet)	$ 1.73
Crude oil and natural gas liquids (per barrel)	$ 22.25

3. Long term debt:

	1997		1996	
	Balance Outstanding	Interest Rate[1]	Balance Outstanding	Interest Rate[1]
Bank loans	$ 133,282	4.07%	$ 212,667	5.15%
Bank loans subject to swaps	200,000	6.77%	87,500	8.66%
Oil indexed debentures, maturing October 2000	200,000	8.26%	200,000	8.26%
9.54% sinking fund debentures, maturing October 2002	12,600	9.54%	13,500	9.54%
	545,882		513,667	
Less current portion	(900)		(900)	
	$ 544,982		$ 512,767	

[1] As at September 30.

The Company has a $500,000,000 syndicated revolving credit facility with an extendible two year revolving period and a six year term period, a $15,000,000 term credit facility with an extendible maturity date of June 1, 2001, and $62,500,000 in operating lines of credit. Advances under the facilities can be drawn in either Canadian or U.S. funds. The facilities bear interest at the bank's prime lending rate, U.S. libor rates plus applicable margins or bankers' acceptance rates plus stamping fees. The margins and stamping fees vary with the debt to cash flow ratio and can range from 0.40 percent to 0.75 percent. Loans under the facilities are unsecured.

In 1992, the Company fixed the rate of interest on $52,500,000 of its bank loans through swap agreements at an average rate of 9.62 percent. These agreements matured in 1997.

In 1996 and 1997, the Company fixed the rate of interest on $200,000,000 of its bank loans through swap agreements at an average rate of 6.77 percent. These agreements mature at various dates as shown below:

Amount	Interest Rate	Maturity Date
$ 35,000	6.96%	September 2001
32,500	6.26%	October 2001
7,500	6.40%	October 2002
40,000	6.92%	February 2007
30,000	7.13%	March 2007
30,000	6.92%	June 2007
25,000	6.45%	July 2007
$ 200,000	6.77%	

Subsequent to September 30, 1997, the Company fixed the rate of interest on a further $53,000,000 of its bank loans at a rate of 4.43 percent. This agreement matures in October 1998.

The oil indexed debentures bear interest at a fixed rate of 5.00 percent per annum plus a variable rate of up to 16.80 percent per annum based upon the average price of crude oil. The effective rate of interest on the debenture has been fixed to maturity at 8.26 percent by an unsecured interest rate swap agreement.

Long term debt maturities and sinking fund requirements for the next five years will be $900,000 in 1998, $900,000 in 1999, $900,000 in 2000, $249,460,000 in 2001 and $84,233,000 in 2002. It is anticipated that the bank loans will be extended and that the oil indexed debentures will be refinanced in 2001. If so, only $900,000 will actually be required to be funded in each of the next five years.

The Company has unused operating lines of credit of $62,126,000.

4. Other credits:

	1997	1996
Long term portion of deferred revenue	$ 15,526	$ 18,910
Deferred future site restoration costs	43,174	36,665
Pension accrual (note 9)	5,699	10,915
Long term portion of restructuring accrual	–	2,000
	$ 64,399	$ 68,490

At September 30, 1997, the estimated future site restoration costs to be accrued over the life of the remaining proved reserves were $110,558,000.

5. Share capital:

Authorized:

Common shares: unlimited
Preferred shares: unlimited
Junior preferred shares, redeemable, participating: unlimited

Issued:

	1997		1996	
	Number of shares	Amount (thousands)	Number of shares	Amount (thousands)
Common shares				
Balance, beginning of year	121,025,087	$ 566,030	120,532,950	$ 560,945
Issued for cash on exercise of stock options	1,173,668	14,011	343,361	3,043
Issued for cash under employee stock savings plan	162,208	2,795	148,776	2,042
Balance, end of year	122,360,963	582,836	121,025,087	566,030
Contributed surplus		153,552		153,552
	122,360,963	$ 736,388	121,025,087	$ 719,582

At September 30, 1997, 8,864,392 common shares were reserved for issuance under the Company's employee stock option plan. Options to purchase 6,066,176 common shares for cash consideration of $8.94 to $17.80 per share were outstanding under the plan. The options are exercisable at various dates to the year 2005.

At September 30, 1997, 426,114 common shares were reserved for issuance under the Company's employee stock savings plan, issuable at market prices.

A shareholder protection rights plan was approved by the shareholders of the Company on February 14, 1996. If a bid to acquire control of the Company is made, the plan is designed to give the Board of Directors of the Company time to consider alternatives to allow shareholders to receive full and fair value for their shares. In the event that a bid, other than a permitted bid, is made, shareholders become entitled to exercise rights to acquire common shares of the Company at 50 percent of market value. This would significantly dilute the value of the bidder's holdings.

6. Per share amounts:

Earnings per common share and cash flow from operations per common share are calculated using the weighted average number of common shares outstanding. The fully diluted cash flow from operations per common share calculations include imputed interest of $3,762,000 (1996 – $3,506,000) calculated at a rate of 4.75 percent (1996 – 6.00 percent) on the proceeds from the exercise of stock options. These amounts are tax effected at a rate of 44.8 percent to calculate fully diluted earnings per common share.

7. Taxes:

The provision for taxes differs from the result which would have been obtained by applying the combined federal and provincial tax rate to earnings before taxes. The difference results from the following items:

	1997	1996
Earnings before taxes	$ 156,654	$ 93,965
Combined federal and provincial tax rate	44.8%	44.8%
Computed "expected" tax	$ 70,181	$ 42,096
Increase (decrease) in taxes resulting from:		
Royalties and other payments to provincial governments	45,914	35,102
Non-deductible depletion	2,288	1,655
Resource allowance	(46,793)	(37,673)
Income tax rebates and credits	(1,935)	(870)
Capital taxes	6,318	5,369
Resource allowance settlement	(4,680)	–
Non-taxable capital gains	(1,008)	–
Other	(1,574)	83
Provision for taxes	$ 68,711	$ 45,762

Property, plant and equipment with a net book value of $41,286,000 (1996 – $44,466,000) has no cost base for income tax purposes.

In November 1997, the Company received a settlement payment from Revenue Canada. The settlement payment related to reassessments of the 1982 to 1992 tax years of certain subsidiaries of the Company. The most significant issue in the reassessments related to the methodology used to calculate resource allowance. Amounts accrued in the year ended September 30, 1997 included a tax refund of $4,680,000 and refund interest of $6,320,000.

8. Sale of investments:

(a) Home Oil International Ltd.

Effective July 31, 1997, the Company sold its investment in Home Oil International Ltd., a wholly owned subsidiary that conducted oil and gas exploration, development and production activities in Argentina. Proceeds were $50,417,000, net of selling costs and cash sold.

A gain of $8,007,000 ($6,008,000 after tax) was recorded on the sale of this investment.

(b) Discovery Petroleum N.L.

Effective December 20, 1996, the Company sold its portfolio investment in the shares of Discovery Petroleum N.L. for proceeds of $5,323,000. A gain of $2,540,000 ($1,760,000 after tax) was recorded on the sale of this investment.

9. Pension plans:

The Company has a non-contributory registered defined benefit pension plan. In June 1995, the plan was amended to give active employees an opportunity to opt out of the plan in favour of a defined contribution alternative. Most employees opted out of the plan. These employees and all new employees accrue future benefits based on defined contributions. Employees remaining in the plan continue to accrue benefits under the defined benefit plan. The plan is funded based on independent actuarial valuations. Plan assets are invested primarily in publicly traded equity and fixed income securities. Retirement benefits are based on the employees' years of credited service and salaries during the last years of employment.

The retirement benefit under the registered plan is subject to a maximum pension as determined under the Income Tax Act (Canada). To the extent this limitation applied, supplemental retirement allowances were provided to qualifying employees at the time so that the total retirement benefits were sufficient to provide the annuity that those employees would have been entitled to without the limitation. To support the Company's obligations under the supplemental plan, the Company has issued a letter of credit to the custodian of the supplemental plan.

In August 1997, the Company purchased annuity contracts in respect of all retired and deferred vested members of the registered plan. Pension assets were used to purchase the annuities. Projected benefit obligations were reduced to reflect this purchase of annuities.

Based on an actuarial valuation dated October 1, 1996, adjusted for the purchase of the annuities, the status of the plans at September 30, 1997 was:

	1997	1996
Pension plan assets	$ 19,222	$ 55,992
Projected benefit obligations	(7,385)	(53,716)
Excess of pension plan assets over projected benefit obligations	$ 11,837	$ 2,276

In 1997, the Company recorded a pension recovery of $4,347,000 (1996 – $2,745,000).

10. Financial instruments:

(a) Interest rate risk

The Company has entered into fixed rate debt agreements and interest rate swap agreements in order to manage its interest rate exposure on debt instruments. These agreements are described in note 3.

(b) Foreign currency exchange risk

At September 30, 1997, the Company had swap agreements covering exchange rate exposure that effectively locked in $US 4,170,000 per month from October 1 to December 31, 1997 at an average exchange rate of $US 0.6926.

(c) Credit risk

A substantial portion of the Company's accounts receivable are with customers and joint venture partners in the petroleum and natural gas industry and are subject to normal industry credit risks. Purchasers of the Company's natural gas, crude oil and natural gas liquids are subject to an internal credit review to minimize the risk of non-payment.

The Company is also exposed to credit risk associated with possible non-performance by counterparties to the interest rate swap agreements. The Company believes these risks to be minimal as the counterparties are major financial institutions which have at least an AA credit rating as determined by recognized credit rating agencies.

(d) Fair value of financial instruments

The carrying amounts of financial instruments included in the consolidated balance sheet, other than long term debt, approximate their fair value due to their short term maturity.

The estimated fair values of long term debt and derivative instruments have been determined based on discounted cash flow analysis using current market interest rates for financial instruments with similar maturities.

The carrying values and estimated fair values of long term debt and derivative instruments are as follows:

	1997		1996	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Bank loans	$ (333,282)	$ (333,282)	$ (300,167)	$ (300,167)
Interest rate swaps on bank loans	$ –	$ (7,901)	$ –	$ (1,831)
Oil indexed debentures	$ (200,000)	$ (198,327)	$ (200,000)	$ (190,952)
Interest rate swap on oil indexed debentures	$ –	$ (17,893)	$ –	$ (22,451)
9.54% sinking fund debentures	$ (12,600)	$ (14,276)	$ (13,500)	$ (14,940)
Foreign currency exchange contracts	$ –	$ 830	$ –	$ 4,052

11. Segmented information:

The Company operates principally in Canada in the oil and gas and pipeline transportation industries. Pipeline transportation activities are currently conducted through the Company's 50 percent interest in Federated.

The services of the pipeline transportation segment are provided to the oil and gas segment under competitive terms and in the normal course of business and have not been eliminated in the consolidated financial statements.

1997		Oil and Gas		Pipeline		Total
Revenues, net of royalties	$	603,781	$	27,859	$	631,640
Operating expenses		(150,744)		(8,873)		(159,617)
General and administrative expenses		(27,694)		(610)		(28,304)
Depletion, depreciation and site restoration		(247,733)		(3,378)		(251,111)
Interest		(34,811)		(1,143)		(35,954)
Earnings before taxes		142,799		13,855		156,654
Taxes		(62,513)		(6,198)		(68,711)
Earnings	$	80,286	$	7,657	$	87,943
Cash flow from operations	$	372,699	$	10,346	$	383,045
Net capital expenditures	$	448,941	$	19,803	$	468,744
Total assets	$	2,245,495	$	57,363	$	2,302,858

1996		Oil and Gas		Pipeline		Total
Revenues, net of royalties	$	481,493	$	27,967	$	509,460
Operating expenses		(109,431)		(7,976)		(117,407)
General and administrative expenses		(26,347)		(721)		(27,068)
Depletion, depreciation and site restoration		(225,998)		(3,585)		(229,583)
Interest		(39,789)		(1,648)		(41,437)
Earnings before taxes		79,928		14,037		93,965
Taxes		(39,526)		(6,236)		(45,762)
Earnings	$	40,402	$	7,801	$	48,203
Cash flow from operations	$	295,815	$	10,945	$	306,760
Net capital expenditures	$	245,906	$	1,470	$	247,376
Total assets	$	2,033,851	$	39,400	$	2,073,251

12. Subsequent event:

On October 6, 1997, the Company purchased an additional 10.63 percent interest in Swan Hills Unit No.1 for approximately $98,000,000. The acquisition involved the partial exercise of rights of first refusal and will increase the Company's ownership interest in the Unit to 30 percent. The acquisition was financed with existing lines of credit.

Year ended September 30, 1997 ($ millions, except per share amounts)	Q1	Q2	Q3	Q4	Total
Revenue before royalties	$ 207.1	$ 199.6	$ 159.9	$ 183.4	$ 750.0
Cash flow from operations	$ 119.3	$ 102.5	$ 76.5	$ 84.7	$ 383.0
Cash flow from operations per common share	$ 0.98	$ 0.84	$ 0.63	$ 0.69	$ 3.14
Earnings	$ 37.2	$ 23.2	$ 8.4	$ 19.1	$ 87.9
Earnings per common share	$ 0.31	$ 0.19	$ 0.07	$ 0.15	$ 0.72
Net capital expenditures	$ 72.2	$ 174.9	$ 97.2	$ 124.4	$ 468.7
Daily sales					
Gas (Mmcfd)	542	543	563	548	549
Oil (Bpd)	26,464	27,834	27,063	28,528	27,472
NGL (Bpd)	6,701	5,752	5,023	5,197	5,669
	33,165	33,586	32,086	33,725	33,141

Year ended September 30, 1996 ($ millions, except per share amounts)	Q1	Q2	Q3	Q4	Total
Revenue before royalties	$ 137.4	$ 152.8	$ 149.3	$ 161.1	$ 600.6
Cash flow from operations	$ 69.8	$ 82.4	$ 75.8	$ 78.8	$ 306.8
Cash flow from operations per common share	$ 0.58	$ 0.68	$ 0.63	$ 0.65	$ 2.54
Earnings	$ 8.8	$ 16.9	$ 11.6	$ 10.9	$ 48.2
Earnings per common share	$ 0.07	$ 0.14	$ 0.10	$ 0.09	$ 0.40
Net capital expenditures	$ 36.3	$ 51.3	$ 48.2	$ 111.6	$ 247.4
Daily sales					
Gas (Mmcfd)	494	503	517	512	506
Oil (Bpd)	24,901	23,645	22,393	25,425	24,097
NGL (Bpd)	6,013	5,329	4,997	5,611	5,489
	30,914	28,974	27,390	31,036	29,586

Financial (millions, except per share amounts)	1997	1996	1995	1994	1993
Revenues					
Oil and gas	$ 705.1	$ 569.3	$ 518.4	$ 539.0	$ 470.4
Royalties, net of ARTC	(118.4)	(91.1)	(84.0)	(99.3)	(83.6)
Pipeline	27.4	28.0	26.8	24.7	20.4
Other	17.5	3.3	3.4	1.1	7.7
	631.6	509.5	464.6	465.5	414.9
Expenses					
Operating	159.6	117.4	113.5	108.9	91.8
Depletion and depreciation	240.7	219.6	209.0	179.1	143.7
General and administrative	28.3	27.1	50.4	47.5	46.4
Interest	36.0	41.4	49.6	50.9	56.0
Future site restoration	10.4	10.0	8.4	7.2	5.1
Minority interest	–	–	–	–	1.5
Restructuring costs	–	–	36.9	–	2.8
	475.0	415.5	467.8	393.6	347.3
Earnings (loss) before taxes	156.6	94.0	(3.2)	71.9	67.6
Taxes					
Current	8.5	12.3	6.8	13.5	26.7
Deferred	60.2	33.5	(4.2)	24.4	10.9
	68.7	45.8	2.6	37.9	37.6
Earnings (loss)	$ 87.9	$ 48.2	$ (5.8)	$ 34.0	$ 30.0
Per common share	$ 0.72	$ 0.40	$ (0.05)	$ 0.31	$ 0.30
Earnings (loss) before restructuring	$ 87.9	$ 48.2	$ 16.7	$ 34.0	$ 31.7
Per common share	$ 0.72	$ 0.40	$ 0.14	$ 0.31	$ 0.32
Cash flow from operations	$ 383.0	$ 306.8	$ 208.3	$ 249.4	$ 197.6
Per common share	$ 3.14	$ 2.54	$ 1.73	$ 2.26	$ 1.97
Cash flow from operations before restructuring	$ 383.0	$ 306.8	$ 241.6	$ 249.4	$ 199.6
Per common share	$ 3.14	$ 2.54	$ 2.01	$ 2.26	$ 1.99
Balance sheet information					
Net additions to property, plant and equipment	$ 468.7	$ 247.4	$ 322.5	$ 351.5	$ 130.0
Corporate acquisitions (dispositions)	$ (50.4)	$ –	$ –	$ 112.5	$ –
Long term debt	$ 545.0	$ 512.7	$ 561.9	$ 467.8	$ 487.0
Working capital (deficiency)	$ (12.2)	$ (19.2)	$ (25.7)	$ (4.6)	$ (8.9)
Shareholders' equity	$ 986.1	$ 881.3	$ 828.0	$ 836.7	$ 573.0
Common shares outstanding at September 30	122.4	121.0	120.5	120.2	104.1
Operating					
Daily sales					
Natural gas (Mmcfd)	549	506	507	440	391
Oil (Bpd)	27,472	24,097	25,628	25,230	25,447
NGL (Bpd)	5,669	5,489	6,253	7,023	7,007
	33,141	29,586	31,881	32,253	32,454
Proven reserves					
Natural gas (Bcf)	1,768	1,798	1,812	1,853	1,801
Oil and NGL (Mmbbls)	130.9	107.7	99.2	105.0	99.1
Proven plus probable reserves					
Natural gas (Bcf)	2,713	2,694	2,739	2,783	2,610
Oil and NGL (Mmbbls)	200.3	165.7	158.9	164.4	146.1
Wells drilled for oil and gas					
Gross	669	335	308	424	310
Net	426	210	230	305	159
Employees					
Calgary	347	293	314	564	530
Field	332	329	347	386	369

In September 1995, a business combination between Anderson Exploration Ltd. and Home Oil Company Limited was accomplished. The business combination was accounted for using the pooling of interests method of accounting. Under this method, the consolidated financial and operating results reflect the historical results of both companies as if they had always been together. This means that the comparative financial and operating results for fiscal 1995 reflect the combined operations of the two companies for that entire year even though the business combination was only accomplished in the last month of that fiscal year. The comparative results for all prior years are presented on the same basis.

Fiscal 1997 is the second full year after the business combination. Supplementary information on the historical results of the two combining entities has been provided for 1995 and prior years. The information enables shareholders and interested parties in the investment community to review the financial and operating history of the two combining companies and their respective contributions to the business combination. This information will not correspond directly to the previously reported historical results of the two companies as accounting policies have been conformed and Home Oil's results have been restated to reflect a change in fiscal year end from December 31 to September 30.

Anderson Exploration Contribution to Business Combination with Home Oil accomplished in September 1995.

Financial (millions, except per share amounts)	1995	1994	1993	1992	1991
Revenues					
Oil and gas	$ 230.0	$ 209.0	$ 136.6	$ 94.7	$ 93.6
Royalties, net of ARTC	(39.2)	(42.9)	(26.1)	(18.1)	(20.8)
Pipeline	–	–	–	–	–
Other	–	0.1	0.1	0.1	–
	190.8	166.2	110.6	76.7	72.8
Expenses					
Operating	42.1	35.2	24.4	20.5	18.6
Depletion and depreciation	93.2	66.7	42.7	30.5	23.7
General and administrative	9.8	8.0	6.2	5.6	4.6
Interest	13.7	8.3	10.0	10.8	8.3
Future site restoration	4.4	3.3	2.0	1.5	–
Minority interest	–	–	–	–	–
Restructuring costs	4.1	–	–	–	–
	167.3	121.5	85.3	68.9	55.2
Earnings before taxes	23.5	44.7	25.3	7.8	17.6
Taxes					
Current	2.2	1.9	0.9	0.8	5.0
Deferred	9.6	18.6	9.4	3.8	6.6
	11.8	20.5	10.3	4.6	11.6
Earnings	$ 11.7	$ 24.2	$ 15.0	$ 3.2	$ 6.0
Per common share	$ 0.21	$ 0.45	$ 0.33	$ 0.08	$ 0.15
Earnings before restructuring	$ 14.0	$ 24.2	$ 15.0	$ 3.2	$ 6.0
Per common share	$ 0.25	$ 0.45	$ 0.33	$ 0.08	$ 0.15
Cash flow from operations	$ 119.0	$ 112.8	$ 69.0	$ 39.1	$ 36.3
Per common share	$ 2.09	$ 2.09	$ 1.52	$ 0.95	$ 0.89
Cash flow from operations before restructuring	$ 123.1	$ 112.8	$ 69.0	$ 39.1	$ 36.3
Per common share	$ 2.16	$ 2.09	$ 1.52	$ 0.95	$ 0.89
Balance sheet information					
Net additions to property, plant and equipment	$ 175.6	$ 178.9	$ 81.6	$ 12.5	$ 33.0
Corporate acquisitions	$ –	$ 70.0	$ –	$ 106.5	$ –
Long term debt	$ 153.3	$ 90.5	$ 90.8	$ 152.2	$ 72.7
Working capital (deficiency)	$ (16.3)	$ (20.4)	$ (12.1)	$ 1.5	$ 1.6
Shareholders' equity	$ 421.5	$ 410.7	$ 276.1	$ 196.3	$ 191.8
Common shares outstanding at September 30	57.2	56.9	49.4	41.4	41.2
Operating					
Daily sales					
Natural gas (Mmcfd)	282	215	160	111	77
Oil (Bpd)	8,606	6,510	4,775	4,131	4,346
NGL (Bpd)	2,040	1,746	1,182	1,617	1,082
	10,646	8,256	5,957	5,748	5,428
Proven reserves					
Natural gas (Bcf)	901	900	755	698	619
Oil and NGL (Mmbbls)	30.4	29.4	19.4	17.7	15.1
Proven plus probable reserves					
Natural gas (Bcf)	1,387	1,378	1,162	1,033	907
Oil and NGL (Mmbbls)	46.7	43.9	28.4	25.4	22.3
Wells drilled for oil and gas					
Gross	136	225	157	43	73
Net	105	172	90	21	54
Employees					
Calgary	105	106	79	65	53
Field	119	110	79	67	61

Home Oil Contribution to Business Combination with Anderson Exploration accomplished in September 1995.

Financial (millions, except per share amounts)	1995	1994	1993	1992	1991
Revenues					
Oil and gas	$ 288.4	$ 330.0	$ 333.8	$ 299.2	$ 343.4
Royalties, net of ARTC	(44.8)	(56.4)	(57.5)	(47.7)	(56.5)
Pipeline	26.8	24.7	20.4	25.2	26.6
Other	3.4	1.0	7.6	3.3	1.0
	273.8	299.3	304.3	280.0	314.5
Expenses					
Operating	71.4	73.7	67.4	72.7	76.7
Depletion and depreciation	115.8	112.4	101.0	100.3	91.7
General and administrative	40.6	39.5	40.2	41.8	53.1
Interest	35.9	42.6	46.0	47.3	50.2
Future site restoration	4.0	3.9	3.1	2.5	0.7
Minority interest	–	–	1.5	1.0	1.8
Restructuring costs	32.8	–	2.8	–	13.2
	300.5	272.1	262.0	265.6	287.4
Earnings (loss) before taxes	(26.7)	27.2	42.3	14.4	27.1
Taxes					
Current	4.6	11.6	25.8	16.1	11.4
Deferred	(13.8)	5.8	1.5	(6.5)	5.3
	(9.2)	17.4	27.3	9.6	16.7
Earnings (loss)	$ (17.5)	$ 9.8	$ 15.0	$ 4.8	$ 10.4
Per common share	$ (0.38)	$ 0.24	$ 0.38	$ 0.12	$ 0.26
Earnings (loss) before restructuring	$ 2.7	$ 9.8	$ 16.7	$ 4.8	$ 18.8
Per common share	$ 0.06	$ 0.24	$ 0.42	$ 0.12	$ 0.47
Cash flow from operations	$ 89.3	$ 136.6	$ 128.6	$ 101.9	$ 111.7
Per common share	$ 1.94	$ 3.31	$ 3.25	$ 2.57	$ 2.83
Cash flow from operations before restructuring	$ 118.5	$ 136.6	$ 130.6	$ 101.9	$ 122.3
Per common share	$ 2.58	$ 3.31	$ 3.30	$ 2.57	$ 3.09
Balance sheet information					
Net additions to property, plant and equipment	$ 146.9	$ 172.6	$ 48.4	$ (2.6)	$ 116.3
Corporate acquisitions	$ –	$ 42.5	$ –	$ –	$ –
Long term debt	$ 408.6	$ 377.3	$ 396.2	$ 474.0	$ 543.2
Working capital (deficiency)	$ (9.4)	$ 15.8	$ 3.2	$ 11.9	$ (5.2)
Shareholders' equity	$ 406.5	$ 426.0	$ 296.9	$ 281.9	$ 277.1
Common shares outstanding at September 30	45.9	45.9	39.6	39.6	39.6
Operating					
Daily sales					
Natural gas (Mmcfd)	225	225	231	197	169
Oil (Bpd)	17,022	18,720	20,672	23,042	24,053
NGL (Bpd)	4,213	5,277	5,825	6,086	4,802
	21,235	23,997	26,497	29,128	28,855
Proven reserves					
Natural gas (Bcf)	911	953	1,046	1,145	1,222
Oil and NGL (Mmbbls)	68.8	75.6	79.7	88.8	107.8
Proven plus probable reserves					
Natural gas (Bcf)	1,352	1,405	1,448	1,548	1,737
Oil and NGL (Mmbbls)	112.2	120.5	117.7	132.8	161.2
Wells drilled for oil and gas					
Gross	172	199	153	120	127
Net	125	133	69	32	46
Employees					
Calgary	209	458	451	481	503
Field	228	276	290	317	341

CORPORATE INFORMATION

BOARD OF DIRECTORS

J.C. Anderson
(1968)
Chairman &
Chief Executive Officer
Calgary, Alberta

Ian D. Bayer +
(1984)
President
Battle Mountain Gold Company
Houston, Texas

W. Gordon Brown, Q.C. ‡
(1982)
Partner, Bennett Jones Verchere
Calgary, Alberta

Noel A. Cleland +
(1995)
Corporate Director
Calgary, Alberta

E. Susan Evans, Q.C. ‡
(1995)
Corporate Director
Calgary, Alberta

J. Richard Harris ‡
(1988)
Consultant
Calgary, Alberta

Charles J. Howard +
(1993)
President
Ausnoram Holdings Limited
Toronto, Ontario

Larry J. Macdonald
(1992)
President & Chief Operating Officer
Calgary, Alberta

John H. Morrish
(1995)
Corporate Director
Surrey, British Columbia

CORPORATE OFFICERS

J.C. Anderson
Chairman &
Chief Executive Officer

Larry J. Macdonald
President &
Chief Operating Officer

David G. Scobie
Senior Vice President &
Chief Financial Officer
Secretary-Treasurer

Alan D. Archibald
Vice President, Production

Henry H. Assen
Vice President, Marketing

Fred E. Baker
Vice President, Exploration

Brian H. Dau
Vice President, Exploitation &
Business Development

Dan F. Kell
Vice President, Land

Richard C. Osborne
Vice President, Pipelines

Arthur H. Williamson
Vice President, Drilling

Gerald S. Read
Controller

+ Member of Audit Committee
‡ Member of Compensation Committee
(Fiscal year first elected as Director)

MANAGERS

Area Exploitation Managers

Scot Collins
Phil A. Harvey
Greg J. Kuran
Kevin L. Stashin
Geoff G. Zakaib

Area Exploration Managers

Steve J. Babcock
Frank J. Gratton
Al J. Onia
Tim B. Watters

Business Development

Sam A. Coles

Drilling

Carl F. Hiscock
Jim N. Peta
(Completions)

Facilities

W.A. (Drew) Livingston

Finance

Linda M. Ellergodt
(Office Services)
George R. Nichols
(Operations Accounting)
M. Darlene Wong
(Financial Reporting)

Land

Lynn M. Gregory
(Administration)

Marketing

Keith J. Fardy
(Natural Gas)
Josie M. MacGillivray
(Liquids)

Pipelines

Chris I. Grayston
(Accounting)
Burdette M. Lehne
(Operations)
Ken W. Murchie
(Engineering)
Barry N. Peterson
(Business Development)

Production

Jan H. Olthof
Walter C. Tersmette
(Safety & Environment)

District Superintendents

Terry J. Clelland
Swan Hills, AB
J. Rob Cursons
Carstairs, AB
Tip C. Johnson
Fort St. John, B.C.
Doug J. Moore
Lloydminster, AB
Ron L. Strandquist
Fairview, AB

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Field Offices
Carstairs, Alberta
Fairview, Alberta
Fort St. John, B.C.
Lloydminster, Alberta
Swan Hills, Alberta

Auditors
KPMG
Calgary, Alberta

Solicitors
Bennett Jones Verchere
Calgary, Alberta

Independent Engineers
Gilbert Laustsen Jung Associates Ltd.
Calgary, Alberta

Registrar & Transfer Agent
Montreal Trust Company of Canada
Calgary, Halifax, Regina, Toronto,
Vancouver, Winnipeg

Stock Exchange
The Toronto Stock Exchange
Symbol: AXL

Annual Information Form
Copies of the Company's Annual Information Form are available on request.

Corporate Governance
Information concerning the Company's corporate governance is presented in the Notice of and Information Circular for Annual General Meeting of Shareholders dated December 29, 1997.

Conversion & Other Information

Volume Reporting
All production, sales and reserve statistics are Anderson Exploration's working interest amounts before deduction of royalties, unless stated otherwise. Where volumes are reported in barrels of oil equivalent, gas is converted to oil at 10 thousand cubic feet (10 mcf) per barrel. This is a commonly used conversion ratio in the Canadian oil and gas industry, but not necessarily reflective of relative energy content or value.

Financial Reporting
All amounts are in Canadian dollars, unless stated otherwise. The Company's fiscal year end is September 30.

Metric Conversion
The petroleum industry in Canada has officially converted to the International System of Units for measuring and reporting. The following table notes conversion factors relevant to this report.

To Convert From	To	Divide By
Thousand cubic feet (mcf) gas	Thousand cubic metres (10^3m^3)	35.4937
Barrels (bbls) oil	Cubic metres (m^3)	6.2898
Feet (well depths)	Metres (m)	3.2808
Miles (distance)	Kilometres (km)	0.6214
Acres (land)	Hectares (ha)	2.5000

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